Exhibit 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA Plaintiff, v. DTE ENERGY COMPANY, and DETROIT EDISON COMPANY Defendants.	)	Civil Action No.

**DECLARATION OF
ROBERT KOPPE**

I, Robert H. Koppe, declare as follows:

(1) I have been asked to evaluate what effect the Monroe Unit 2 (Monroe 2) boiler upgrades would have on the amount of power that the unit will generate in the future. For the reasons described below, I concluded that the Company should have expected that the availability of Monroe 2 to generate power would be greater after the 2010 planned outage than it had been before. I also concluded that the Company should have expected that a substantial amount of the increase in availability would be due to the three boiler tube replacements. I further concluded that the Company expected that the utilization of the unit would be greater in the future than it had been in the past. The combination of increased availability and increased utilization should result in a large increase in the amount the unit generates per year. A considerable amount of the increase in generation will be due to the increased demand on the unit, that is, it will be due to increased utilization of the unit. Another considerable amount of the increase in generation will be due to the increase in unit availability that was due to the boiler upgrades. It may be that generation would have increased had the tube replacements not been implemented. However, the forecast increase in generation would have been much less but for the replacements.

MY EXPERIENCE

(2) The following is a brief summary of my background and experience. More detailed information can be found in my resume, which is in Appendix A. The documents I considered in my analysis are cited in the text and footnotes. My company is being compensated at the rate of $100 per hour for my work on this matter.

(3) I received a BS in Wood Products Engineering from the SUNY College of Forestry and an MS in Nuclear Engineering from the Ohio State University. I completed all the course work toward a Ph.D. in Nuclear Engineering at MIT, but did not complete the degree. From 1968 to 1974, I worked for the Consolidated Edison Company of New York, first as a nuclear engineer and then as manager of the nuclear engineering division. From 1974 to the present, I have been a consultant, working on nuclear and coal-fired electric generating units. Work I have done that is relevant to my work on this case includes:

- Development of industry databases on power plant performance, including the NERC GADS database, which is described later in this declaration, and which I used in developing my conclusions in this case;
- Several studies of the utility industry and other industries with respect to collection of experience data and use of that data for decision making;
- Many analyses of industry-wide experience with generating unit operations;
- Reviews and audits of design and/or operations of numerous individual generating units; and
- Calculation of the anticipated amount of future electricity generation for many individual generating units. Several of these calculations involved the changes in generation expected to result from specific changes in the design and/or operation of the unit.

THE EFFECT OF THE THREE BOILER TUBE REPLACEMENTS ON THE AVAILABILITY OF MONROE 2

INTRODUCTION

(4) Starting on March 13, 2010, Detroit Edison shut down Monroe 2 for a long planned outage. This outage lasted for more than twelve weeks.[1] The unit typically has a long planned outage once each four years.[2] There are some shorter planned outages.[3] The 2010

[1] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.
[2] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 4.
[3] Data the Company reported to NERC GADS.

planned outage was longer than most long planned outages at the unit. This was because both the economizer and the pendant reheater were replaced in 2010.[4]

(5) During the 2010 planned outage, the Company made a number of major improvements to the unit. The three improvements that I was asked to look at each involved replacement of a major component of the unit's boiler. Specifically, these three replacements involved:

- Complete replacement of the entire economizer;
- Complete replacement of both banks of the pendant reheater (also known as the high temperature reheater); and
- Replacement of a substantial amount of tubing in the furnace waterwall component of the boiler.[5]

(6) For each of these three replacements, the new tubes contained design features that were a significant improvement relative to the original design.[6]

(7) During the outage, the Company also made a number of other significant improvements to the unit. These included:

- Replacement of the generator exciter with a modern design;
- Replacement of the generator lead box; and
- Re-winding the generator rotor.[7]

(8) Based on my experience and the experience of the industry, I concluded that the Company should have expected that the availability of Monroe 2 to generate power would be greater after the 2010 planned outage than it had been before. I also concluded that the Company should have expected that a substantial amount of the increase in availability would be due to the three boiler tube replacements. Specifically, the Company should have expected that, but for the three replacements, the increase in the unit's availability would have been substantially smaller.

[4] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 4. (The data the Company reported to NERC GADS show that the last major planned outage at the unit was early in 2005, which is five years before the 2010 outage, not four. Also, the 2005 planned outage was almost as long as the 2010 outage. I presume that the Company's statements reflect a longer-term view.

[5] EPA inspection Documents, page 2 "Capital Project Status"

[6] See subsequent sections of this declaration for details and citations.

[7] EPA inspection Documents, page 2 "Capital Project Status"

(9) My analysis follows. Further general background information on coal-fired electric generating units (coal units) and on outages and the performance of coal units is set forth in Appendix B.

METHODOLOGY FOR DETERMINING THE EXPECTED INCREASE IN EAF AS A RESULT OF THE REPLACEMENTS

(10) This section is devoted to a description of my methodology for determining the magnitude of the equivalent availability factor (EAF)[8] change that the Company should have expected to result from a boiler tube replacement. This same methodology has been used in several New Source Review enforcement cases including the *Ohio Edison* and *Cinergy* cases.

(11) For each replacement, I prepared a list of GADS events (outages and deratings) that occurred during the 60 months pre-replacement (the pre-replacement period) and were due to problems that the Company should have expected would be avoided in the future as a result of that replacement. Dr. Sahu identified a 24-month baseline period within the 60 months. He took the events I had identified that occurred during the baseline period. He calculated the increase in the amount of electricity the unit would be capable of generating (the increased EAF) that would occur if those events were precluded in the future and everything else stayed the same. Based on that increase in EAF and on the expected output factor for the unit, he calculated the amount of additional generation (and thus the amount of additional emissions) that the Company should have expected. Throughout this declaration, I refer to the methodology and my (or our) calculation of EAF losses or EAF changes, recognizing that the actual calculations of EAF changes were done by Dr. Sahu.

(12) In the following sub-sections, I discuss the:

- logic for the method;
- identification of the problems that would be eliminated by a replacement;
- identification of the GADS events that had been due to those problems;
- determination of the effect of contemporaneous activities on the unit's EAF; and
- conservatisms in the methodology.

[8] As explained further in Appendix B, EAF is a measure of how much of the time the unit was available to operate.

Logic for Our Method.

(13) The logic behind our methodology is:

- Prior to being replaced, the component had design deficiencies and/or was wearing out. These problems caused failures of the component;
- Those component failures were causing outages and/or deratings of the unit;
- Those outages and deratings were reducing the EAF of the unit;
- Replacing the component would eliminate these failures post-replacement. This would preclude some of the outages and deratings that had been occurring. This would increase the EAF of the unit: it would increase the amount of electricity the unit was available to generate;
- Around the time that the three replacements were implemented, the Company was doing other things to increase the EAF of the unit. These other increases in EAF would cancel out the deleterious effects of any degradation of other equipment in the unit that might be taking place; and
- At the time of the three replacements, the other things that the Company was doing would likely cause some increase in Monroe 2's EAF beyond the increase that was due to the replacements. We ignored these further increases and calculated only the increase directly due to the replacement alone. (This conservatism is incorporated into the methodology.)

What Problems Would Be Eliminated by a Replacement?

(14) To answer this question, I reviewed various DTE documents such as:

- the justifications that the Company prepared for the replacement;
- the Company's descriptions of other upgrades that it made to Monroe 2 before and during the 2010 planned outage;
- The Company's GADS data, which describe the causes of each of the outages that occurred during the 60 months prior to the start of the 2010 planned outage;
- Testimony given by Company witness Mr. Paul Fessler in 2009.

(15) Based on the information in these documents, I determined what equipment was replaced. I then determined how the new component(s) differed from the original(s); what problems the Company should have expected would be eliminated by the replacement; and the expected effect of the replacement on the EAF of the unit.

Which GADS Events Were Caused by Failures That Would be Eliminated by the Replacement?

(16) For each replacement, I reviewed each outage and derating at Monroe 2 during the pre-replacement period (the 60 months pre-replacement) to determine if it was due to the equipment that was replaced and if it was due to a failure mechanism that the Company expected (or should have expected) to be eliminated once the replacement was

implemented. In doing this, I utilized information from the Company's GADS data. The Company provided GADS data that listed all the events (outages and deratings) that the Company had reported for each unit.[9] (See later in this declaration for a description of GADS event data.)

(17) For each replacement, I prepared a table of GADS events for use by Dr. Sahu.[10] For the pre-replacement time period, my intention was to include only events that had all of the following characteristics:

- It was due primarily to a problem that was addressed by the replacement;
- It was due entirely to problems that would not have been expected post-replacement; and
- It occurred at a time when the unit would otherwise have been operated.

(18) To achieve this intention, I included in my tables only those pre-replacement events that met the following criteria:

- I included an event only if I was reasonably sure that the primary reason for the event was a problem that the Company should have anticipated would be eliminated once the replacement was implemented;
- I did not include an event that was due to a component that was replaced but was due to a problem that was not addressed by the replacement (e.g., failures due to exogenous factors such as operator errors or dropped objects); and
- Based on the Company's GADS data, I determined that, during the 60 months pre-replacements, the Company operated Monroe 2 whenever that unit was available to operate.[11] Based on that fact, I determined that the Company would have operated the unit during each hour it was shut down due to problems with any of the components of the boiler, had those problems not occurred.

[9] There are other kinds of events in GADS. Only outages and deratings are relevant to this discussion.
[10] In the end, I combined the listings of events for all three replacements into a single table – Table 2. There were several other outages that were probably due to problems that were resolved by the replacements that I did not include in Table 2. I did not include those outages because I did not have the information I would need in order to be reasonably certain that the outages were caused by problems that were resolved by the replacements. I listed those outages in Table 3.
[11] The Company operated the unit whenever it was not shut down for an outage. This is the same as saying that the Company never put the unit in reserve shutdown.

What Effect Should the Company Have Expected Other Components and Activities to Have on the EAF of the Unit?

(19) Contemporaneous with the three boiler tube replacements, other things were happening that might have affected the EAF of the Monroe 2. These include:

- Aging of other components at the unit;
- Other component replacements, which are not at issue in this matter;
- Detroit Edison's on-going programs to improve the availabilities of its units[12]; and
- Technological improvements that were taking place throughout the industry.

(20) A priori, the overall effect of all these contemporaneous occurrences might be to increase the EAF of the unit beyond the increase due to the three replacements at issue or it might be to decrease the EAF, canceling out some or all of the increase due to the three replacements at issue. Dr. Sahu only needed to calculate the portion of an EAF increase that was due to a replacement at issue. Therefore, we did not need to quantify any further increases due to contemporaneous occurrences. However, we did need to be sure that the overall effect of those occurrences was not likely to be negative.

(21) To determine if the overall effect of contemporaneous occurrences was likely to be negative, I considered five kinds of information:

- My experience of the kinds of replacements and improvement programs that were implemented throughout the industry during the same time period;
- The Company's descriptions of replacements and improvement programs it was implementing to improve the overall EAF of its units;
- My experience of the expectations of increases in EAFs throughout the industry;
- My analyses of the changes in EAFs that actually occurred throughout the industry; and
- The Company's own expectations with regard to increasing EAFs of its units.

(22) My analyses for each of the three replacements are described later in this declaration. Based on my analyses, I concluded that the Company should have expected that the overall effect of everything that was happening at and to each unit (other than the three replacements at issue) would have been some further increase in EAF or, at least, no decrease. This means that the Company should have expected that the EAF of Monroe 2 would increase by an amount greater than or equal to the amount attributable to the three replacements. (Nonetheless, the EAF increase calculated by Dr. Sahu for the three replacements together is only that portion of the increase that was due to those replacements alone.)

---

[12] These include a program to reduce the frequencies of boiler tube leaks and a program to reduce the durations of planned outages. See elsewhere in this declaration for citations concerning these programs.

Conservatisms in My Methodology.

(23) My methodology for determining the EAF increase that the Company should have expected due to a replacement is conservative: it understates the EAF increase. There are three reasons for this:

(24) The Method Does Not Take Account of EAF Decreases That Would Have Occurred without the Replacement. In deciding whether to replace a component, a utility will calculate the amount of additional EAF it expects as a result of the replacement.[13] The increase in EAF is calculated as the difference between:

- The expected future EAF if the component is replaced (usually this is more than recent experience, because the new component will be more reliable than the old); and
- The expected future EAF if the component is not replaced (usually this is less than recent experience, because the old component will continue to deteriorate).

(25) This approach, which I have found is universal in the utility industry, is illustrated in Figure 1. I was asked to calculate increased EAF in a different way. Specifically, I was asked to calculate increased EAF as the difference between:

- The expected future EAF after the component was replaced, and
- The actual historical EAF before the component was replaced.

(26) This approach is also illustrated in Figure 1. I have found that this approach almost always understates the increase in EAF due to a replacement. That is because it only accounts for the increase in EAF above the historical level. It does not account for the decrease in EAF that would have occurred without the replacement, but was avoided as a result of the replacement.

(27) Effects of Other Improvements That the Company Made in the Same Time Period as a Replacement. At the time of the three replacements, the Company was making other improvements to Monroe 2. Some of those improvements should have been expected to result in some additional increase in the unit's EAF, beyond what was expected as a result of the replacements. Had it not been for the replacements, the components would have continued to deteriorate, resulting in further decreases in the unit's EAF. These decreases would have offset (cancelled out) some or all of the increases due to the other improvements. Thus, some or all of the increases that should have been expected in unit

[13] Ultimately, utilities are interested in the additional generation attributable to a replacement. Additional generation is calculated as additional EAF times an expected utilization factor.

EAF due to the other improvements are attributable to the replacement at issue: they would not have taken place without that replacement.

(28) The analyses that Dr. Sahu and I did only take account of increases in EAF that were due to the replacements alone. They do not take account of further increases in EAF that were due to other Company activities, but would not have occurred without the replacement. Thus, our results understate the increases in EAF that were attributable to the replacements.

(29) The same reasoning I described two paragraphs back also applies to increases in output factor (OF) for the unit. OF is the power the unit actually generated divided by the power it could have generated had it always operated at its capability (full power) when it was operating.[14] The Company expects that the OF for Monroe 2 will be greater post-replacements than it was pre-replacements. Had some or all of the three replacements not been implemented, the EAF of Monroe 2 may have decreased as a result of deterioration of the components. This would have offset some or all of the increase in generation that was attributable to increased OF. Thus, some or all of that increase was attributable to the replacement: it would not have happened without the replacement.

(30) Omission of Some Historical Unavailability. Prior to implementation of the replacement, problems with the three components of the boiler were causing outages and/or deratings at Monroe 2. These events were reducing the amount of electricity the unit was available to generate: they were reducing the EAF of the unit. By eliminating these causes of EAF losses, the replacements will increase the unit's EAF, increasing the amount of electricity generated and, thereby, increasing emissions. The bigger the pre-replacement EAF losses due to the three components of the boiler, the bigger the increase in EAF (and in emissions) as a result of the replacements will be.

(31) The data in Table 2 tend to understate the pre-replacement EAF losses that were due to problems that were subsequently resolved by the replacements. This means that Dr. Sahu's calculations tend to understate the increases in EAF (and therefore the increases in generation and emissions) that the Company should have expected. There are four factors that tend to make my analyses understate pre-replacement EAF losses related to replacements. Some of these factors likely had little or no effect on some or all of my results for the replacements. Taken together, they likely caused some conservatisms in my results for some of the replacements.

[14] In prior cases, I have generally used utilization factor where I here use OF. The OF is numerically equal to the utilization factor I have used in prior cases.

(32) The four factors are:

- I only included a GADS event in Table 2 when I could be reasonably sure it was caused by a problem that was addressed by one of the three replacements. For some events, I could not find a complete description of the event cause in the GADS data. I identified several outages that were probably due to problems that were resolved by the three replacements. These are listed in Table 3. As a result, I may have omitted some events that I should have included;[15]
- It is my experience that replacement of major components often results in a decrease in the amount of work to be done during planned outages. This in turn sometimes results in shorter planned outages in the future. It may also permit the unit to run longer between planned outages in the future. It is likely that some of the replacements at issue resulted in shorter planned outages and/or permitted less frequent planned outages. The Company has said that it is working to reduce the durations of planned outages at its coal units. I did not have the kind of information I would need to determine how much the planned outage hours would be decreased as a result of the three replacements. Therefore, I assumed no change;
- The replacements together will eliminate many outages per year at Monroe 2. Startup and shutdown of the unit for these outages had been causing degradation of other components in the unit. The replacements will decrease the number of startup/shutdown cycles on the unit and this will decrease the number of outages caused by deterioration of other components. I did not take any account of this effect in my analyses; and
- When the unit is started up after an outage, its power level starts out low and is ramped up to full power over a period of several hours. At the start of some outages, the power is ramped down over a period of a few hours. During these startup and shutdown ramps, the unit is limited to less than full power. These ramps should be reported to GADS as deratings. During the 60 months pre-replacements, the Company never reported any startup or shutdown ramps. This means that the EAF losses in my Tables 2 and 3 understate the actual losses. It is my experience that for the kinds of outages listed in Tables 2 and 3, the failure to report startup and shutdown ramps causes the EAF losses due to those outages to be understated by five to ten percent.

BACKGROUND

(33) Monroe 2 entered commercial service around 1973.[16] This means that it has now been in operation for about 37 years. At the time units such as Monroe 2 were built, there was a general expectation in the industry that the units would operate for 30 to 35 years and would then be retired, or relegated to peaking service. Thus, Monroe 2 has already

[15] I reserve the right to supplement my results should more information become available.
[16] My estimate based on information in EPRI report NP-1191, dated September 1979.

operated beyond its originally expected life. It is not surprising that some components, including some components of the boiler, have worn out.

(34) A unit such as Monroe 2 will usually operate for every, or almost every, hour that it is available. In fact, during the five years (60 months) preceding the 2010 planned outage, the unit actually operated for every hour it was available.[17] Each hour the unit is shut down due to a boiler tube leak is another hour the unit would have operated, but did not. If the amount of outage time due to boiler tube failures is reduced by one hour, the unit will operate for that additional hour. (The unit operates every hour it is able (available) to operate. During that one additional hour, a large unit such as Monroe 2 will burn hundreds of tons of coal, and will emit several tons of SO_2 and NO_X. A typical large coal unit such as Monroe 2 will emit more than 40 tons of SO_2 in a day of operation. This means that increasing the availability of a large unit such as Monroe 2 by only one day per year will increase emissions by more than enough to trigger PSD.

THE THREE BOILER TUBE REPLACEMENTS

(35) In this section, I discuss each of the three boiler tube replacements that were done during the 2010 planned outage. In the following section, I discuss the expected effect of the three replacements, and other contemporaneous work, on the availability of Monroe 2.

The Economizer Tube Replacement

(36) A well-designed economizer should operate for decades, while causing only infrequent outages of the unit. When an economizer wears out, and starts causing more frequent outages, this is almost always due to coal-ash erosion. Combustion gasses (smoke) from the furnaces pass over the outside of the tubes in the economizer. If the velocity of the gasses is too high, ash from the coal, which is carried by the combustion gasses, wears away the outsides of the tubes. In some designs, ash plugs the spaces between some of the tubes. This reduces the area available for the combustion gasses to flow through the economizer, which increases the velocity of those gasses, which increases the rate of wear of the tubes.[18] Eventually the walls of the tubes become so thin in places that the pressure of the water inside the tube causes the tube to burst. When this happens, the unit must be shut down while the leak is repaired. The key to designing a good economizer is to provide enough space between the tubes so that the gas velocity is relatively low and so ash-plugging between the tubes is minimized.

[17] My analysis of data the Company reported to NERC GADS.
[18] It also reduces the efficiency of the unit.

(37) Some economizers, especially some of those that were designed in the 1960s, had high gas velocities, and wore out in as little as 10 to 20 years, or even less. Prior to the 2010 replacement, the economizer at Monroe 2 was still original equipment, which means it had been in service for about 37 years.[19]

(38) During recent years, the tubes had worn to the point where economizer tube leaks were causing outages of the unit several times per year, and the amount of outage time per year due to the economizer had been increasing with time.[20] The Company expected that the amount of outage time per year caused by the economizer would continue to increase with time. This expectation is consistent with my experience and the experience of the industry. In its justification for the economizer replacement, the Company said that:

> "The Unit 2 economizer tubes have been damaged during lengthy service in an erosive environment. Tube failures and forced outages are occurring at an increasing rate. Objective: operation of the unit without forced outages caused by economizer tube failures."[21]

(39) In addition to 37 years of wear due to being blasted by coal ash, the economizer tubes had another problem. In most economizer designs, the tubes in each horizontal row are stacked directly above the ones below. As a result, the combustion gasses can pass through vertical paths (lanes) between the columns of tubes. This arrangement helps to reduce the accumulation of ash between tubes. It also helps to protect tubes from being eroded by the coal ash. At Monroe 2, some of the tubes had bowed out into the gas lanes, causing more plugging, and exposing the tubes to more intense erosion. According to EPA's inspection notes, the Company stated that replacement of the economizer was due to

> "increased forced outages due to misaligned tubes, which affect the flue gas flow around the tubes causing unwanted velocity gradients inside the boiler, and pluggage in the backpass."[22]

(40) The Company said that it replaced the entire economizer.[23] I take this to mean that all the tubing in the economizer was replaced. I have not seen any indication that the tube headers in the economizer were replaced, and I assumed that they were not.

(41) Better economizer designs require more space between tubes. This requires that the overall volume of the economizer be relatively large. The problem that is faced when an

---

[19] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.
[20] My analysis of data the Company reported to NERC GADS.
[21] Detroit Edison's PAT review request form for PMP project 5240, replacement of economizer at Monroe 2, revision dated 2/5/10.
[22] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.
[23] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.

economizer in an existing unit is replaced is how to reduce gas velocities and reduce plugging, while working within the relatively small space in the unit. The industry has developed designs that address this issue. Also, the industry has developed better supports for economizer tubes, which reduce the likelihood of tubes bowing into the gas lanes.

(42) I do not know what design improvements the Company incorporated in the replacement economizer. However, the Company described the replacement as being to "[d]esign an economizer which is less susceptible to erosion and which meets performance criteria set by DTE."[24] There is a lot of experience with various economizer designs, and some designs result in longer economizer lives than others.

(43) The preceding indicates that the Company expected that the replacement economizer tubes will last longer than the original ones had. Given the experience of the industry with improved economizer designs, I concluded that this was a reasonable expectation.

(44) Industry experience is that a well-designed new economizer will operate for many decades with only very occasional tube leaks. Therefore, the Company should have expected that the replacement economizer would cause very little outage time after it was installed. This would mean that there would be much less outage time per year due to the economizer after the replacement than there had been before. The Company's justification for the replacement stated that:

> "This project is to remove and replace the economizer on Unit 2 at Monroe Power Plant. With this project, the plan is to address the lost availability due to economizer tube leaks and improve reliability. The replacement will reduce future outages…"[25]

<u>The Pendant Reheater Replacement</u>

(45) The reheater at Monroe 2 consists of four banks of tubes. There are two banks of tubes that are oriented horizontally. These banks are located in the back section of the boiler. There are two banks of tubes that are oriented vertically. The tubes in these two banks hang down through the boiler roof into the top potion of the boiler. The tubes in these banks are called pendants, because they hang from above. The pendant tubes of the reheater can also be referred to as the high temperature reheater because, as described below, they operate at higher temperatures than the horizontal tubes.

---

[24] Detroit Edison's PAT review request form for PMP project 5240, replacement of economizer at Monroe 2, revision dated 2/5/10.

[25] Detroit Edison's appropriation request form for PMP project 5240, replacement of the economizer at Monroe 2, dated 2/26/09.

(46) During the 2010 planned outage, the Company replaced both of the pendant banks of tubes in the reheater. The horizontal reheater was not replaced.[26]

(47) The steam coming from the high-pressure section of the turbine passes first through one and then the other of the two horizontal banks of tubes in the reheater. It then passes through one and then the other of the two pendant banks of tubes, and then goes to the intermediate-pressure section of the turbine. As a result of the preceding, the steam is hotter when it passes through the pendant components than it is when it passes through the horizontal components. In addition, the combustion gasses are hotter when they pass over the outsides of the pendant tubes than they are when they pass over the horizontal tubes.

(48) One result of the preceding is that the tube walls in the pendant reheater operate at higher temperatures than the tube walls in the horizontal components. This means that the pendant tubes are more susceptible to internal and external corrosion. Another potential problem with tubes that operate at high temperatures is a phenomenon known as creep. Creep involves a long-term degradation of the crystal structure of steel at high temperatures. After a long time, typically decades, creep can weaken the steel that makes up a tube wall, to the point that the tube bursts. This can happen even in the absence of substantial amounts of corrosion. Creep would never be an issue in the horizontal banks of reheater tubes, but could be a problem in the pendant reheater.

(49) During a recent EPA inspection, the Company stated that replacement of the pendant reheater was due to increased forced outages related to creep failure.[27] The Company stated that this was the first time that the reheater pendants had been replaced in their entirety.[28] This means that most of the tubing in the reheater had operated for about 37 years prior to being replaced.

(50) For a given operating temperature and pressure, the rate at which creep progresses can be reduced by using higher-grade steels and/or by using thicker tube walls. The use of thicker walls is usually avoided because it reduces the amount of heat that is transferred through the tube walls. The Company's justification for the reheater replacement stated that the replacement would "[u]pgrade materials to account for current and future boiler operating temperature conditions."[29] This indicates to me that the Company expected that the pendant reheater would experience higher temperatures in the future than it had in the past. I do not know why the Company expected this. In any case, the replacement

[26] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.
[27] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.
[28] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.
[29] Detroit Edison's PAT review request form for PMP project 705, replacement of pendant reheater at Monroe 2, revision dated 4/21/10.

reheater was made of higher grade steels than the original had been, and this will increase the amount of time the tubes will be able to operate before experiencing failures.

(51) The Company's justification for the reheater replacement stated that:

> "The boiler tubes in the Reheat Pendants are failing. Unit 2 has experienced reheater pendant failures resulting in forced outages. Analysis done by the Boiler Tube Task Force predicts more frequent failures in the future. Objective would be to improve the reliability of Unit 2 by replacing the secondary reheater inlet and outlet pendants during the next Unit 2 major periodic outage."[30]

The Furnace Waterwall Tube Replacement

(52) In Monroe 2, all the walls of the boiler are lined with tubes, referred to as waterwall tubes. Waterwall tubes also form the division wall. This wall divides the furnace of the boiler into two equal spaces. The wall runs from the front of the furnace to the rear, half way between the two side walls.[31] In a well-designed boiler, waterwall tubes will last for many decades. They may cause some outages, but they will not wear out, that is, they will not reach a point where the number of tube failures per year increases substantially with the passage of time.

(53) Some units, especially units that were designed during the 1960s have furnaces that are too small. In such units, there can be corrosion on the outsides of the waterwall tubes, on the side of each tube that faces into the furnace. This fire-side corrosion reduces the thickness of the tube walls. Eventually, the walls can become so thin that the tube bursts. Such corrosion is generally concentrated in the lower part of the furnace, in the area around the burners. It is not a problem at the top of the furnace or in the top of the boiler or in the back pass. At some units, the rate of corrosion was increased as an unintended result of the installation of low NO_X burners. The industry has found that coating the outsides of the waterwall tubes with a corrosion resistant metal can reduce the rate of progress of the corrosion.

(54) From the Company documents I have seen, it appears that the waterwall tubes at Monroe 2 have been subjected to fire-side corrosion. In 2010, the Company replaced about 2,000 square feet of furnace waterwall tubes.[32] The Company described the replacement as

---

[30] Detroit Edison's PAT review request form for PMP project 705, replacement of pendant reheater at Monroe 2, revision dated 4/21/10.
[31] Figure 1 "Monroe Boiler Model" (EPA000011274).
[32] Since waterwall tubes line the walls of the boiler, it is customary to describe tube replacements in terms of the number of square feet of wall area that was replaced. Replacement tubes are often shipped to a plant in the form of

"[r]eplace damaged waterwall panels with new tubes which are clad with a corrosion resistant alloy."[33] The Company also stated that the replacement was to "[r]eplace waterwall surface internal to the Unit 2 boiler to improve reliability due to water tube failure from reduced wall thickness of Boiler Tubes."[34]

(55) The Company's justification for the waterwall replacement describes different areas to be replaced. These areas total about 1786 square feet.[35] During a recent EPA inspection, the Company said that the total area replaced during 2010 was about 2000 square feet.[36] This was not the first time the Company had replaced waterwall tubes at Monroe 2. During the planned outage of the unit in November-December of 2007 the Company spent $5.1 million in capital to replace some waterwall tubes.[37] This cost is somewhat less than what the Company planned to spend on the waterwall tube replacement in 2010. Based on the preceding, I concluded that during the planned outages in 2007 and 2010, the Company replaced a total of about 3500 square feet of furnace waterwall tubes.

(56) The Company stated that the 2000 square feet replaced in 2010 represented about 4% of the waterwall tube surface in the boiler. This means that the boiler has a total of about 50,000 square feet of waterwall surface. However, most of this surface is in parts of the boiler that are not susceptible to fire-side corrosion. Based on my experience, I estimated that something on the order of 10,000 square feet of the waterwall surface in Monroe 2 is susceptible to serious fire-side corrosion. This means that the 3500 square feet that the Company replaced in the last two and a half years is about one-third of the tubing that is susceptible to major fire-side corrosion.

(57) It may well be that the Company replaced some tubing prior to 2007, so that the total amount replaced has been more than 35% of the susceptible tubing. During a recent EPA inspection, the Company said that waterwall tubes are replaced frequently during planned and forced outages. [38] Of course, the Company would replace the more heavily corroded tubes first. The replacement tubing is coated with a corrosion-resistant alloy. The original tubing was not. All of the preceding means that the problem with fire-side corrosion

---

panels. A panel is made up of many tubes lined up in parallel, with a small space between each pair of tubes. That space if filled with weld metal, which joins all the tubes into a single sheet or panel.

[33] Detroit Edison's PAT review request form for PMP project 5685, replacement of water wall panels at Monroe 2, revision dated 1/15/10.

[34] Detroit Edison's PAT review request form for PMP project 5685, replacement of water wall panels at Monroe 2, revision dated 1/15/10.

[35] Detroit Edison's PAT review request form for PMP project 5685, replacement of water wall panels at Monroe 2, revision dated 1/15/10.

[36] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

[37] Fessler testimony, pages 19 – 21 says the work was done during the period July 2007 through June 2008. Data the Company reported to GADS shows only one planned outage during that time period – during November and December of 2007.

[38] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

should become less severe with time. On the other hand, some level of on-going problems must be expected. During the 60 months prior to the 2010 planned outage, the unit experienced only two unplanned outages that were due to leaks in furnace waterwall tubes.

(58) Throughout the industry, when a major section of waterwall tubes is replaced at a unit, it often results in a substantial increase in the EAF of the affected unit. Monroe 2 only experienced two outages due to furnace waterwall tube failures in a five year period. This means that the possible increase in EAF due to the waterwall replacement is small. However, the replacement will prevent future decreases in unit availability that would have occurred had the waterwall tubing been allowed to continue to deteriorate.

(59) During a recent EPA inspection, the Company stated that the purpose of the waterwall tube replacement had been to reduce forced outages due to corrosion.[39]

THE OVERALL EFFECT OF THE THREE REPLACEMENTS ON THE UNIT

(60) During the 2010 planned outage at Monroe 2, the Company replaced all of the tubing in two components of the boiler and a substantial portion of the tubing in another component. Each of these three components had the following characteristics:

- Most of the tubing in the component was original, and had been in service for about 37 years;
- In recent years, the tubes had been leaking and thereby causing considerable amounts of outage time at the unit;
- The Company expected that the amount of outage time due to the tubes would increase with the passage of time (if the tubes were not replaced);
- The replacement tubing was new, so it did not have any of the damage that had accumulated in the original tubing during 37 years of operation; and
- The design of the replacement tubing was a considerable improvement over the original design.

(61) Based on this information (and on my experience and the experience of the industry), I concluded that the Company should have expected that the new boiler components would cause little or no outage time in the future, where the old tubes had caused considerable amounts of outage time in the past. The Company's justifications for the replacements indicate that it did expect considerable reductions in outage time.

[39] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

(62) All else being equal, a reduction in the amount of outage time caused by the boiler components will result in an increase in the amount of time the unit is available to generate electricity. Each additional hour the unit is available is an additional hour it will operate. (As I said previously, Monroe 2 operates for every hour it is available to do so.) Each additional hour of operation results in an increase in the amount of electricity the unit actually generates. Generating more electricity requires the burning of more coal, which results in the emission of more pollutants.

(63) There is only one thing that could happen that would result in the availability of the unit not increasing after the replacements are implemented. This is that other components in the unit could cause more outage time in the future, offsetting the reduction in outage time due to the replacements. In the following section, I address the effect of the other components in the unit.

THE EFFECT OF OTHER COMPONENTS

(64) The vast majority of work that is done in a generating unit serves only to maintain the availability of that unit. One component fails and causes an outage in one month, and is fixed. Another fails and causes an outage the next month, and is fixed. In the absence of major upgrades, this pattern will tend to repeat. The availability of the unit will tend to go up and down with time depending on which components fail, and when they fail. However, the unit's long-term availability does not change with the passage of time.

(65) Despite the preceding, major improvements in a unit can cause long-term increases in that unit's availability. During the last 35 years, this has occurred at hundreds of units throughout the industry.

(66) There is very strong evidence that the replacements at Monroe 2 will increase the long-term availability of that unit. This evidence consists of:

- The potential for improvement;
- The magnitude of the replacements;
- Other improvements being made; and
- The Company's expectations.

(67) I address these four factors in the following sections.

The Potential for Improvement

(68) During the 60 months preceding the replacements, Monroe 2 achieved an average EAF of less than 81.0%.[40] It is my experience that generating units similar to Monroe 2 are capable of long-term EAFs in the range of 88 to 90%. Thus, the unit had considerable room for improvement.

The Magnitude of the Replacements

(69) Throughout the industry, most of the thousands of components in a unit cause no, or almost no, outage time. Some components cause small amounts of outage time. A few cause large amounts of outage time. By far the biggest cause of outage time is the boiler tubes. On average for the industry, boiler tubes cause nearly half of all the unplanned outage time at coal units. They are also responsible for some of the planned outage time. All of the preceding is also true for Detroit Edison's coal units. In 2008, a Company witness testified that:

> "The remaining 8.81% of fossil fleet unavailability in the July 2007 through July 2008 time frame was due to unplanned outages. Most of these outages were boiler related with the most predominant issue being boiler tube leaks in waterwall, superheater, reheater or economizer sections."[41]

(70) As I described in Appendix B, a single major boiler component that has worn out can cause more unplanned outage time than all of the thousands of other components in a unit combined. If a worn-out boiler component is not replaced, it can, in some situations, cause the unit to become completely inoperable. Thus, a single boiler component can cause substantial decreases in the availability of a unit. Replacing such a boiler component will then result in a substantial increase in the unit's availability.

(71) It could be that, after one boiler component was replaced, another component would become worn out. This other component might cause as much outage time in the future as the first component had caused in the past. In such a situation, the availability of the unit might not increase.

(72) For any coal unit, and especially for a unit as important as Monroe 2, I would expect that the Company periodically inspects and tests each boiler component. This would give the Company a reasonable expectation as to how long each component will be able to operate before it wears out, and begins causing increasing numbers of outages. The documents I

---

[40] This is the result of my calculation based on data the Company submitted to NERC GADS. Because of a problem with some of the Company's GADS data, I calculated an upper bound on the EAF. That was 81.0%. I estimate that the actual EAF for the unit was about 80.0%. Because I could not calculate that number precisely, I based my discussion on the conservative (upper bound) value.

[41] Fessler testimony, page 12.

have seen do not indicate which, if any, boiler components at Monroe 2 the Company expects to wear out in the near future. Even in the absence of this knowledge, I concluded that there is very little chance that wear-out of other boiler components could cause so much outage time in the future as to offset the reductions in outage time due to the replacements. This conclusion comes from the very unusually large magnitude of the work that was done during the 2010 planned outage.

(73) One can think of the Monroe 2 boiler as having six major components: the economizer, the horizontal reheater, the pendant reheater, the horizontal superheater, the pendant superheater, and the waterwalls. During 2007-2010, the Company completely replaced two of those six components, and replaced a substantial part of the susceptible portion of a third. Only if two or three of the other three components all wore out in the next five years might one expect that those components might cause as much outage time in the future as the three components that were replaced had caused in the past. There is some chance that one of the other three boiler components will wear out in the next five years. However, there is a greater chance that that will not happen. The probability that two or three of those three components will all wear out in the next five years is minute.

(74) Thus, the sheer magnitude of the work done during 2010 makes it extremely unlikely that wear-out of other components of the boiler would offset the reductions in outage times due to the replacements. Therefore, I concluded that the replacements should be expected to result in a considerable increase in the availability of the unit.

Other Improvements Being Made

(75) Monroe 2 is one of the Company's base-loaded coal units. In 2008, a Company witness testified that the Company expected the average EAF for all the base-loaded coal units would increase from 81.8% in 2007 to 83.5% in 2010. The expected improvement was due to a reduction in the impact of unplanned outages, from 12.0% in 2007 to 9.1% in 2010.[42] Based on these numbers, I calculated that the Company expected an increase in the average amount of planned outage time at the base-loaded coal units. This is not surprising. The Company planned major upgrades at many of the coal units during 2008 – 2010. One example of this is the major upgrades that the Company planned for, and actually implemented at, Monroe 2 in 2010. The 2010 planned outage at Monroe 2 was scheduled to last more than 12 weeks. This was longer than most planned outages at the unit. It resulted in the impact of planned outages at the unit being much higher in 2010 than it had been in previous years, including 2007.

(76) The Company's witness stated that the forecasts of plant availabilities were based on input from the plant staff and plant-headquartered reliability engineers, historical unit

[42] Fessler testimony, page 12.

performance, the known maintenance and operational status of each unit, and future planned outage schedules and work scope.[43]

(77) The Company's witness testified that the Company's efforts to improve the overall availability of its fossil units consisted of efforts to reduce the frequency of unplanned outages and efforts to reduce the lengths of planned outages. There is a section of this witness's testimony that describes the effort to reduce the frequency of unplanned outages. This section is devoted entirely to the effort to reduce the frequency of boiler tube failures.[44] This indicates to me that the Company's expectation of a reduction in the amount of unplanned outage time was mostly or entirely due to expected reductions in the frequency of boiler tube leaks. Since the expected increase in unit availability was due to the reduction in the amount of unplanned outages, it follows that the expected increase in unit availability was due mostly or entirely to a reduction in the number of boiler tube leaks. Based on my experience, the experience of the industry, and what I know about the condition of the Company's units, I concluded that the Company's expectations were reasonable.

(78) In addition to the program to reduce the number of boiler tube leaks, the Company had a program to improve the way it managed planned outages. The purpose of that effort was to "…decrease the duration and overall cost of planned outages without impacting the scope of work performed.[45] Given this effort, and the major upgrades that have been implemented, I concluded that the Company should expect that, once it has completed most of the major improvements at the base-loaded coal units, the average amount of planned outage time at those units will decrease. This will result in some additional increase in the average availability of the units.

(79) When asked to summarize the Company's efforts with respect to the availability of its fossil generating units, the Company's witness said that "Detroit Edison has invested significant capital and maintenance dollars over the last several years to maintain and improve generation unit availability…"[46] This testimony shows that the Company understands that the EAFs of its coal units can be increased. It also shows that the Company understands that capital improvements, including replacements of major boiler components, can contribute to increases in EAF.

(80) In summary, with respect to its fleet of fossil units, the Company expected that:

[43] Fessler testimony, page 12.
[44] Fessler testimony, page 13.
[45] Fessler testimony, page 13.
[46] Fessler testimony, page 14.

- The average availability of all the units would increase during the period from 2007 to 2010;
- This increase would be due entirely to a reduction in the amount of unplanned outage time;
- That reduction would be due mostly or entirely to a reduction in the number of boiler tube leaks; and
- Improved availability would result from investment of "…significant capital and maintenance dollars…"

(81) All of this is consistent with what I have seen at other units throughout the industry. Therefore, I concluded that the Company's expectations were reasonable.

(82) The Company's testimony I have quoted referred to the average for all of the Company's base-loaded coal units. Monroe 2 is one of those base-loaded coal units. Monroe 2 is essentially identical to three of the Company's other base-loaded coal units (Monroe 1, 3, and 4). The problems experienced by those other Monroe units, and the upgrades at those units, were generally similar to what was happening at Monroe 2. The Company implemented or planned similar component replacements at a number of other coal units. However, replacement of three major boiler components at one time, as was done at Monroe 2, is rare in the industry. In recent years, DTE has been making a major effort to upgrade its coal units. This means that the Company has been implementing more major improvements than I would normally expect. Even in these circumstances, replacement of three major boiler components at one unit at the same time is unusual.

(83) The Company's witness also listed some major capital projects that were being done at other coal units and did not involve boiler tube replacements.[47] There were also some replacements at Monroe 2 and at other coal units that did not involve boiler tube replacement. It is my experience that replacements such as these would either prevent future decreases in availability or result in small increases. At Monroe 2, there were two things that were done that would tend to increase the EAF of the unit. During the pre-replacement period, Monroe 2 had experienced a total of about 41 days of outage time due to failures of the main leads from the generator and of the main transformer. During the 2010 planned outage, the Company replaced the generator lead box. In addition, the Company bought a spare transformer that would serve Monroe 2 and similar units. These two actions should greatly reduce the chance of any future occurrence of the problems that caused the 41 days of outage time pre-replacement.

[47] Fessler testimony, pages 19-27.

(84) The preceding is all entirely consistent with the Company's testimony regarding the average of all its fossil units. Specifically, for all the units: availability would increase; the increase would be due to a reduction in the number of boiler tube failures; and this reduction would be largely due to replacement of boiler components that had worn out.

(85) The Company's witness testified that the availability of the base-loaded coal units would increase from 81.8% in 2007 to 83.5% in 2010. This increase did not include the improvements at Monroe 2. At the time of the testimony, Monroe 2 was scheduled for a planned outage of 12 weeks in 2010. This outage was longer than a usual major planned outage, because of the difficulties of replacing the economizer and the pendant reheater during the same outage. Largely as a result of this long planned outage, the Company forecast that the EAF for Monroe 2 in 2010 would only be 69%.[48] This means that other units would have experienced EAFs greater than the 83.5% average for all the units. The Company should have expected that the EAF of Monroe 2 would increase after 2010, when the effects of all the work that was done during the 2010 planned outage, including the three boiler tube replacements, would be felt, and when future planned outages would be expected to be shorter.

(86) The Company forecasted an average increase in EAF for the base-loaded coal units of 1.7 percentage points. This occurred even though some units, including Monroe 2, were expected to have lower availability in 2010, as a result of long planned outages to implement major upgrades. I concluded that, as Monroe 2 and other units completed their major upgrades, the average availability of these units would increase further.

<u>The Company's Expectations</u>

(87) As I stated earlier, during the five years (60 months) preceding the 2010 planned outage, Monroe 2 achieved an average EAF that was less than 81.0%. In a recent letter to EPA, the Company provided its forecasts of EAFs for Monroe for each of the calendar years 2010 through 2014. For the four years after the replacements (2011 through 2014) the average EAF is 84.3%. Thus, the Company itself was forecasting that the EAF for the unit will be at least 3.3 percentage points higher post-replacements than it had been pre-replacements. This is consistent with my expectations, as described in the preceding paragraphs.

(88) An increase in EAF of 3.3 percentage points corresponds to an additional 12 days of operation of the unit each year. Remember that Monroe 2 will emit more than 40 tons of

[48] DTE letter to EPA, dated 6/3/10.

SO_2 in a day. Thus, the increase in EAF that the Company expected was many times the increase needed to trigger PSD.[49]

(89) I also looked at the EAF and outage factors during the baseline periods selected by the Company for NO_X and SO_2 in its March 12, 2010 letter. Based on the information the company reported to GADs, I found the following:

TABLE 1 MONROE UNIT 2 BASELINE OPERATING STATISTICS			
Baseline	Planned outage factor	Equivalent unplanned outage rate (EUOR)	EAF
7/06 – 6/08	5.0	14.5	81.3
10/06 – 9/08	5.0	16.6[50]	79.3

Planned outage factor is the equivalent of the "periodic" row in the PROMOD data from the Company's June 3, 2010 letter, while EUOR is the equivalent of Random Outage Rate. Table 1 demonstrates that the expected improvement in EAF was due to a decrease in forced outages. The projected average EUOR for unit 2 for the years 2011 to 2014 was 8.7%, significantly less than the rate during the baseline periods.[51] As I discuss below, some or all of this improvement must be due to the project.

MY RESULTS REGARDING THE EFFECTS OF THE REPLACEMENTS ON THE AVAILABILITY OF MONROE 2

(90) During the spring 2010 planned outage, Detroit Edison replaced three boiler components. Specifically, the Company replaced:

- All of the tubing in the economizer component of the boiler;
- All of the tubing in the pendant reheater component of the boiler; and
- Some of the tubing in the waterwall component of the boiler.

(91) I looked at the data the Company reported to NERC GADS for the 60 months immediately preceding the boiler component replacements. All three replacements were

[49] As I said in the preceding, I believe that the actual EAF for the unit pre-replacements was about 80.0%. The difference between this pre-replacements value and the Company's forecasted post-replacement value of 84.3% is 4.3 percentage points. This corresponds to an additional 15.7 days of operation of the unit per year.

[50] The actual equivalent unplanned outage rate is likely slightly higher and the actual EAF slightly lower than I show here for reasons discussed elsewhere in this declaration.

[51] Company's June 3, 2010 letter to EPA.

done during the planned outage that started in March of 2010. Therefore, the 60 months preceding the replacements were from March of 2005 through February of 2010.

(92) Table 2 shows information about those outages and deratings that occurred during the 60 months pre-replacements and were due to problems with the tubes that were replaced. The information in Table 2 all came from data that the Company reported to NERC GADS.

TABLE 2
OUTAGES THAT WERE DUE TO BOILER TUBES THAT WERE REPLACED IN SPRING 2010

Event Start Date	Event End Date	Outage Duration (hours)	Derating EFPH	Outage Cause
4/3/06	4/9/06	124.8		Economizer tube leak
4/17/06	4/19/06	54.9		Economizer tube leak
4/22/07	5/7/07		11.4	Economizer slagging or fouling
5/7/07	5/9/07		1.1	Economizer slagging or fouling
5/9/07	5/11/07		2.2	Economizer slagging or fouling
5/11/07	5/12/07		1.6	Economizer slagging or fouling
5/12/07	5/15/07		2.1	Economizer slagging or fouling
5/15/07	5/23/07	205.0		Economizer slagging or fouling
8/7/07	8/14/07		8.1	Economizer slagging or fouling
2/12/08	2/15/08	75.9		Economizer tube leak
3/23/08	4/2/08	237.3		Economizer tube leak
5/9/08	5/13/08	83.0		Economizer tube leak
6/9/08	6/14/08	123.0		Economizer tube leak
7/31/08	8/3/08	68.6		Economizer tube leak
8/27/08	9/1/08	115.0		Economizer tube leak
5/19/09	5/24/09	120		Secondary reheater tube leak
9/6/09	9/10/09	85.8		Economizer tube leak
1/25/10	1/29/10	113.9		Economizer tube leak

(93) I concluded that the Company should have expected that the probability of outages due to similar problems would be very low post-replacements. This conclusion was based largely on the experience of the industry with similar boiler component replacements. That experience is that new boiler components usually operate for at least 10 or 20 years, and often longer, with a low rate of occurrence of tube leaks.[52] Because of this

[52] Sometimes, there may be some failures in the weeks immediately after a unit starts up with a new boiler component. When they occur, such failures are usually due to defects in welds that were made when fabricating or installing the new section of tubes.

experience, utilities usually base their economic evaluations of component replacements on an expectation that the new tubes will not cause any outage time, at least for the first 10 or 20 years of operation. Statements in DTE's justifications for the three replacements, which I have cited elsewhere, indicate that the Company also expected little or no outage time due to the new tubes post-replacements.

(94) Table 3 shows information about four other outages that occurred during the 60 months pre-replacements. This information also comes from data that the Company reported to NERC GADS.

TABLE 3
OUTAGES THAT WERE PROBABLY DUE TO BOILER TUBES THAT WERE REPLACED IN SPRING 2010

Outage Start Date	Outage End Date	Outage Duration (hours)	Outage Cause
10/2/05	10/9/05	157.9	First reheater tube leak
1/16/06	1/20/06	99.6	Furnace wall tube leak
8/14/07	8/18/07	93.4	First reheater tube leak
12/6/09	12/11/09	114.6	Furnace wall tube leak

(95) I concluded that it is likely that some or all of these four outages were due to problems with tubing that was replaced during the planned outage of the unit in the Spring of 2010. However, the information I had about those outages was not detailed enough for me to be reasonably certain. In the following paragraphs, I describe why I am reasonably certain about the outages listed in Table 2, and not so certain about those listed in Table 3.

(96) One of the three replacements at issue involved replacing all of the tubing in the economizer of Monroe Unit 2. The Company said that the economizer was experiencing fouling of the tubes (plugging of the spaces between some tubes with coal ash) and also tube leaks. The Company reported that 10 of the 12 outages listed in Table 2 were caused by leaks in economizer tubes. It reported that one of the outages and all of the deratings were due to fouling of the economizer tubes. Since the Company replaced all of the economizer tubes in 2010, I concluded that all of the outages and deratings that are listed in Table 2 and were due to leaks or fouling in the economizer were due to problems with the tubes that were subsequently replaced.

(97) Among all the coal units in the US, there are many different arrangements of reheaters. The most common arrangement is that steam first passes through one or more horizontal banks of tubes, called the horizontal or primary reheater, and then through one or more

pendant banks, known as the pendant or high temperature reheater. NERC GADS has two cause codes for reheater tube leaks. These are 1060 “first reheater tube leaks”, and 1070 “second reheater tube leaks”. When I developed the NERC GADS cause codes 30 years ago, I intended that leaks in the horizontal reheater would be reported as cause code 1060 and leaks in the pendant reheater would be reported as cause code 1070. Some data reporters report as I had intended. Others report all reheater tube leaks as cause code 1060. This is because of an ambiguity in the way I wrote the cause code list.[53] At least some people at Detroit Edison took this view. During a recent EPA inspection, the Company stated that it does not make any distinction between the first and second reheaters and was not clear why it was identified as such in the GADS data.[54]

(98) The Company reported three outages due to leaks in the reheater tubes. Two of these were reported as having been due to the first reheater, and one due to the second reheater. Since the Company replaced the pendant reheater and not the horizontal reheater, I expect that most of the leaks in the reheater would have been in the pendant component.

(99) Given the preceding, I concluded that it is likely that all three of the outages that were reported as having been due to reheater tube leaks were actually due to leaks in the pendant reheater. I could be reasonably certain that the outage that was reported as having been due to the secondary reheater was in fact due to a leak in the pendant (secondary) reheater. I could not be so certain that the two outages that were reported as having been due to the first reheater were really due to the pendant reheater. Therefore, I included them in Table 3.

(100) The other replacement involved a portion of the waterwall tubes in the lower portion of the furnace component of the boiler. The Company reported two outages during the 60 months that were due to leaks in furnace waterwall tubes. Of course, the Company would replace those portions of the tubes that had deteriorated the most, and were most likely to cause outages. Because I could not be reasonably certain that the leaks that caused the two outages were in tubing that was replaced in the spring of 2010, I listed those two outages in Table 3.

[53] In a small number of units, steam is reheated twice. For those units, there is a first reheater, with a first and a second section, and a second reheater, also with a first and second section. At units such as Monroe 2, which has only one reheater, some data reporters regard the entire reheater as the first reheater. They rightly say that the unit does not have a second reheater.

[54] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

THE UTILIZATION OF THE INCREASED AVAILABILITY OF MONROE 2

(101) If a unit is able to operate for some number of additional hours per year, the potential additional generation (in MW-hrs) is the product of the unit's capability times the number of additional hours. For example, Monroe 2 has a capability of 795 MW – that is the maximum output the unit can generate consistently when all equipment is working normally. If Monroe 2 operates at full power for an additional 100 hours, it will generate an additional 79,500 MW-hrs of electricity (795 * 100 = 79,500).

(102) Monroe 2 always operates when it is able to operate, that is, it always operates when it is available. However, it does not always operate at full power – it does not always operate at its capability. Sometimes the unit is derated – that is, it is limited to something less than full power due to some equipment problem. At other times, the unit is operated at lower power levels because DTE's customers do not want all the power the unit can generate. This is especially true late at night.

(103) One measure of the performance of a generating unit is the output factor (OF). For a given period of time, the OF for a unit is the power the unit actually generated divided by the power it could have generated had it always operated at its capability (full power) when it is operating. For example, let us say that, for some time period, the OF for Monroe 2 was 80%. This means that, for all the hours the unit operated, its average output was 80% of full power. For Monroe 2, full power is 795 MW, so 80% of full power is 636 MW.

(104) During the 60 months pre-replacements, the OF for Monroe 2 averaged less than 82.6%.[55] It does not show any trend to increase or decrease during that time period. I also calculated OF for the baseline periods selected by the company and found a OF of 80.8% for the NO_X baseline period and an OF or 81.5% for the SO_2 baseline period.

(105) The Company's projections for the years post-replacements show OFs increasing steadily, from 88% in 2010 to 96% in 2014. For the four years after the replacements, 2011 through 2014, the Company's forecasts show an average OF for Monroe 2 of 92%.[56]

---

[55] The company spreadsheet "Presentation Steam Unit Summary PSCR" produced as part of its supporting materials for the September 2009 PROMOD run gives the capacity factor and EAF for the unit for each calendar year 2005 through 2009. (2009 represent a mix of actual data and a projection, since the analysis was submitted in September 2009). For these give years, I calculated the average CF and the average EAF. The ratio of CF to EAF was 82.6%. Because the Company reported deratings of the unit during those five years, the OF for the unit must be less than CF/EAF. Based on the preceding, I concluded that the OF for the unit pre-replacements was certainly less than 82.6%.

[56] DTE's letter dated 6/3/10 gives values for the "loading factor" for each year from 2010 through 2014. Based on other data given in that letter, I calculated that loading factor is the same as OF.

(106) For sake of illustration, let us say that the average OF for the unit was 83% pre-replacements and was expected to be 92% post-replacements. Let us further say that the unit is expected to be available (and, therefore, to operate) for an additional 100 hours per year in the future as a result of the replacements.

(107) If the OF for the unit does not increase, the additional 100 hours of availability will result in additional generation of 65,985 MW-hr per year (795 * 100 * 0.83 = 65,985). If the OF increases to 92%, the additional generation will be 73,140 MW-hr per year. (Note that Dr. Sahu calculated the increase in availability that would be expected to result from the boiler tube replacements. The 100 hours I am using here is simply for illustration, and was chosen because it is a round number.)

(108) In the preceding illustration, the entire 73,140 MW-hr per year of additional generation was due to the boiler tube replacements – none of the increase would have occurred but for the projects.[57]

(109) It is logical to conclude that if unit availability increases, generation will also increase. Projects such as the component replacements at issue here are justified based on economics: the cost of the work is weighed against the additional income to be generated from selling additional electricity. It would make no sense to do these types of projects if the utility did not anticipate operating the unit more in the future.

(110) I understand that Dr. Sahu calculated increases in emissions based on the OF that the company experienced in the respective baseline periods. Those OFs are significantly less than the 92% the Company forecast for the four years after the replacements. This will cause the emissions increases calculated by Dr. Sahu to be conservative – they will be lower than what would realistically be expected.

[57] In the illustration, 65,985 MW-hr of additional generation was due solely to the replacements – it would have occurred even if the OF for the unit did not increase. The other 7,155 MW-hr of additional generation was due to the combined effects of the replacements and the increase in OF. Both the 65,985 and the 7,155 are attributable to the replacements. Neither would have occurred but for the replacements.

THE COMPANY'S TREATMENT OF THE EFFECT OF INCREASED EAF ON GENERATION

INTRODUCTION

(111) The Company recently submitted results of PROMOD projections that it submitted to the Michigan Public Service Commission in September 2009. Some of the key inputs to those projections were forecasted future values of the EAF for Monroe 2.[58] As I described previously, the Company's forecasted EAFs for the unit are substantially higher than the actual EAF the unit achieved during the 60 months pre-replacement.[59] In terms of the EAFs for Monroe 2, the three boiler replacements are far and away the most significant things that have happened to the unit in recent years. Nonetheless, in its June 1 and 3, 2010 letters to EPA, the Company is now claiming that it forecasted future EAFs for the unit, and forecasted that the unit's EAFs would increase, without any consideration of the fact that the replacements were being done.

(112) The Company's present claim is inconsistent with its own statements two years ago. It is also inconsistent with the basic logic of generating unit availability. I address those two issues in the following sections.

PRIOR COMPANY CLAIMS

(113) Two years ago, the Company was trying to justify its plans to spend hundreds of millions of dollars on major upgrade replacements at its fossil units. Much of the money was to be spent on boiler component replacements, including replacement of the economizer and the pendant reheater at Monroe 2. In that context, a Company witness testified that the Company expected substantial increases in the EAFs of its base-loaded coal units, one of which is Monroe 2. Moreover, information in that witness's testimony shows that all or most of the expected increase in EAF was due to boiler component replacements at those base-loaded coal units.

(114) Two years ago, the Company's position was that it had forecasted that EAFs would increase, as a result of major upgrades. In forecasting future EAFs at that time, the Company must have taken account of the expected benefits of those major upgrades, including the boiler component replacements. If it had not done so, then its justification for the upgrades would have been very misleading.

---

[58] DTE letter to EPA, dated 6/1/10.
[59] See discussion earlier in this declaration.

(115) Two years ago, the Company wanted to convince state regulators that its forecasts of future EAF were thorough. At that time, the Company witness testified that:

> "The Detroit Edison forecasted plant availabilities are based on input from Plant Staff and plant-headquartered Reliability Engineers, historical unit performance, known maintenance and operational status of each unit, and future planned outage schedules and work scope." [60]

(116) Monroe plant staff and plant reliability engineers would have known about the upcoming boiler component replacements on Unit 2. They would have known that, in terms of effects on the future EAF, these replacements were far and away the most important thing that was happening to the unit. When a single boiler component at any unit wears out, this becomes one of the biggest maintenance issues at that unit. At Monroe 2, three boiler components had worn out. Even the most cursory consideration of the "…known maintenance and operational status…" of the unit would have had to include the condition of the boiler tubes. Worn out boiler components require a large amount of work during each planned outage. Even the most cursory consideration of the "…future planned outage schedules and work scope…" would have had to include the condition of the boiler tubes.

(117) Despite all the preceding, the Company now claims that its forecasts of future EAFs of the unit were made without any consideration of the major upgrades.

(118) Another way of looking at this issue is as follows. The Company might simply have forecasted that the future EAF of the unit would be the same as the historical value. Some utilities do that, without any consideration of the condition of the unit in question. However, the Company forecast that the EAF of Monroe 2 would increase substantially. This must have been based on some consideration of the condition of the unit. Even the most cursory consideration of the condition of the unit must have taken account of the replacements.

THE LOGIC OF GENERATING UNIT EAF

(119) For PSD, the Company could have forecast how much future emissions would be increased as a result of the replacements. One way to do that would have been to forecast the future emissions based on the Company's baseline expectations and the EAF for Monroe 2 that was expected if the replacement was not implemented, and then make a second forecast based on all the same assumptions except that the EAF for Monroe 2 would be that which was expected if the replacement was implemented. In order to

[60] Fessler testimony, page 11.

isolate the effect of the replacement, the two forecasts should have been based on all the same assumptions, except that one forecast would be based on the replacements being done and one on the replacements not being done.

(120) The Company should have expected that the boiler components would cause hundreds of hours of outage time per year in the future if they were not replaced.[61] It also should have expected that those components would cause little or no outage time per year in the future if they were replaced.[62] Because of the preceding, any forecasts the Company would make that took account of the replacements would show more outage time per year in the future if the replacements were not done than they would show if the replacements were done.

(121) There would be hundreds more hours of outage time per year if the replacements were not done than there would be if they were done. There would have been hundreds fewer available hours per year but for the replacements. This means that the forecast EAF would be at least four percentage points lower if the replacements were not done than it would be if they were.[63]

(122) The Company forecasted that the EAF of the unit would increase. It now suggests (in the June 1, 2010 letter to EPA) that this forecast was made without any consideration of the replacements. Even without considering the effects of the replacements, the Company forecasted an increase in EAF. I have just shown that consistent forecasts will always show the future EAF being higher if the replacements are done than if they are not. The preceding leads to the following conclusions:

- Had the Company forecast the future EAF of Monroe 2, taking account of the expected effect of the replacements, that forecast future EAF would inevitably have been higher than the actual historical EAF;
- Had the Company forecast the future EAF of Monroe 2, assuming that the replacements would not be implemented, that forecast future EAF would inevitably have been lower than the forecast EAF taking account of the replacements being done;

[61] The events listed in Table 2 alone caused an average of about 287 hours of outage time at Monroe 2 per year, during the five years (60 months) pre-replacement. For reasons I describe earlier in this declaration, this almost certainly understated the amount of outage time that was being caused by the three boiler components pre-replacement. The Company said that the amount of outage time due to these tubes was increasing with time. Given that increase, and the experience of the industry (that the number of leaks in a worn-out boiler components increases with time) the Company should have expected that the existing tubes would cause more outage time in the future than they had done in the past.
[62] This is based on statements in the Company's justifications for the replacements. It is consistent with industry experience and expectations, as I described elsewhere in this declaration.
[63] Three hundred and fifty additional hours of outage time per year will reduce the EAF for a unit by 4.0% (100 * 350 / 8766 = 3.99 percentage points).

- The forecast EAF assuming no replacements might still be higher than the actual historical EAF. In that case, some of the forecast increase in EAF would be due to the replacements, and some would not. That is, but for the replacements, there would still have been an increase in EAF but the magnitude of that increase would have been smaller; and
- The forecast assuming no replacements might be lower than the actual historical EAF. In that case, all of the forecast increase would be due to the replacements.

(123) The Company expected an increase in EAF. Had it accounted for the effects of the replacements, it would still have expected an increase. But for the replacements, the magnitude of the expected increase would have been smaller, and might have been negative. Some or all of the expected increase in EAF was due to the replacements – it would not have been expected but for the replacements.

THE COMPANY'S "CAPABLE OF ACCOMMODATING" ARGUMENT

(124) The Company forecasted that Monroe 2 would generate more power post-replacements than it had done pre-replacements. It claims that the expected increase in generation was all due to increased demand on the unit, and none of the increase was due to the replacements. One of the arguments it uses to support this claim involves the amount of generation the unit was capable of accommodating pre-replacement.

(125) The Company calculated how much power it says Monroe 2 could have generated during the pre-replacements baseline period it selected. It then calculated how much power it had forecasted that the unit would actually generate post-replacements. The Company claims that the forecasted actual generation post-replacement is less than the possible generation pre-replacements. It seems to claim that this alone proves that the forecast increases in generation were not due to the replacements. There are two things wrong with this argument:

- The Company's calculation overstates the amount of power the unit could have generated pre-replacements; and
- Even if one accepts the Company's calculation, its argument is illogical.

EAF OVERSTATES THE AMOUNT OF ELECTRICITY THE UNIT COULD HAVE GENERATED

(126) The Company's calculation of possible pre-replacements generation is based on the assumption that the EAF of a unit represents the output that unit could have produced had it been asked. This is not true. The reality is that EAF overstates how much a unit could have generated, often by a large amount. For all but a few of the hundreds of units I have looked at in the last 35 years, the reported EAF overstated the amount of electricity the unit actually could have generated.[64] Depending on the unit, a reported EAF will overstate possible generation by somewhere between two percentage points and as much as 10 to 15 percentage points.

(127) The EAF for a unit is calculated based in part on the assumption that, whenever the unit was operating, it could have operated at 100% power, or at the power level to which it was limited by any reported deratings. The EAF of a base-loaded unit, such as Monroe 2, overstates what the unit could actually have generated, because utilities almost never report all the deratings that were experienced by a unit.

(128) Whenever the output of a unit is limited to less than 100% of full power, the unit is said to be derated. Each derating reduces the amount of electricity a unit can generate. Each time a derating exists but is not reported, the reported EAF overstates the amount the unit could have generated if asked. Consider a unit that has a physical problem that limits its output to 80% of full power. Because of reduced demand, the unit is actually being operated at 70% of full power. If demand increased, the unit could actually produce an additional 10% of full power (from 70% up to 80%). If the derating was not reported, EAF would be calculated based on the assumption that the unit could have generated an additional 30% of full power (from 70% all the way up to 100%). As a result of failure to report some deratings, the EAF for a unit will substantially overstate the amount of additional electricity that unit could have generated.

(129) It is my experience that few, if any, units report all deratings to GADS. Personnel at most units inadvertently overlook some deratings when reporting to GADS. Moreover, utilities often deliberately fail to report some kinds of deratings: particularly work done during low demand periods and power ramps before and after outages.

(130) During times when demand is low, and the output from a unit is reduced, utilities will often do maintenance on equipment, especially coal handling equipment. This work is usually not reported as causing deratings. However, had the unit actually been asked to

[64] Utilities do not report EAF directly. EAF is calculated by applying a standard formula to data that utilities do report. For simplicity, I refer to reported EAFs. This should be understood to mean "EAFs calculated by applying the standard formula to the data reported by the utility".

run at full power during those periods, it would not have been able to do so, since the maintenance work would still have been needed.

(131) When a unit starts up after an outage, its output is initially low and then increases (ramps up) over a number of hours. During those hours following each outage, the unit is limited to less than full power – it is derated. However, most utilities do not report these startup ramps. Similarly, units are often ramped down in power before an outage. Again, the unit is derated. Most utilities do not report these deratings.

(132) During the pre-replacements time period, Monroe 2 experienced many outages. The Company did not report any startup or shutdown ramps associated with any of those outages, even though such ramps must have existed. This alone means that the reported EAF for Monroe 2 substantially overstates the amount of electricity it would have been able to generate, had it been asked. To the extent that the Company failed to report other deratings, as all utilities do to some extent, the reported EAFs further overstate the amount the unit could have generated.

(133) In looking at other units that are similar to Monroe 2 throughout my career, I have found that the failure to report startup and shutdown ramps alone causes EAF to overstate possible generation by around two percentage points. I have also found that failure to report other deratings often causes the reported EAF for a unit to overstate possible generation by another two percentage points, and sometimes considerably more. Based on the preceding, and my experience, I concluded that the reported EAFs for Monroe 2 most likely overstate the amount the unit could have generated pre-replacements. The magnitude of this overstatement is most likely in the range of three to four percentage points of EAF.

(134) In any event, I calculated the EAF for the unit for the company's selected NO_X and SO_2 baseline periods. For the SO_2 baseline period, the EAF was 81.2% and for the NO_X baseline period it was slightly less than 79.3%. As I said earlier, those EAFs substantially overstate how much power the unit could have generated during those periods. However, even accepting those numbers, these EAFs are less than what the company forecast to generate in 2013. Thus, the unit was *not* capable of accommodating the additional generation forecast.

THE COMPANY'S ARGUMENT IS ILLOGICAL

(135) Figure 2 shows a typical week in the life of a typical base-loaded coal-fired generating unit. This figure is highly stylized and does not represent any specific unit exactly. Nonetheless, it gives a realistic representation of how such a unit is operated.

(136) The system dispatcher always wants this unit to operate. Therefore, the unit always operates when it is able – whenever it is not broken. On Wednesday, this unit could not run – it was broken. It had a leak in a boiler tube. Had the unit been able to run, it would have run. It did not run, solely as a result of that boiler tube leak. On each of the other six days in the week, the unit was able to run, so it did run.

(137) On each day, the dispatcher wants the unit to run at 100% power during the day, when customers are using a lot of electricity, and at 54% of full power at night, when customers are using a lot less. In Figure 2, the amount of electricity generated through the week is shown in yellow.

(138) What would happen if I undertook the replacement of the worn-out boiler tubes, so there would be no outages due to those tubes in the future? Pre-replacement, the unit was available to operate six days per week, so it did operate six days per week. Post-replacement, it will be available to operate seven days per week, so it will operate seven days per week. During that additional day (Wednesday in our stylized example) the dispatcher will want the unit to operate at 100% power during the day and at 54% power at night; and that is what it will do. Figure 3 shows the situation post-replacement. Post-replacement, the unit runs the same for the six days; and generates the same amount of power – still shown in yellow. In addition, the unit now runs on Wednesday as well. Of course, it generates more power – shown in red. The total power generated post-replacement is more than the generation pre-replacement. The increase is due solely and entirely to the replacement.

(139) Despite the preceding, one could apply the Company's argument and conclude that the replacement did not cause the increase in generation. Following the Company's argument, one would look at Figure 2. One would note that, pre-replacement, the unit could have generated more power than it actually did. To do this, the unit would have had to operate at 100% power at night, when no one wanted that added power. Running the unit at full power at night would have been wasteful and irresponsible; but the Company says it could have done so.

(140) Pre-replacement, the unit could have generated more than it did (the yellow in Figure 2), by running at full power at night. It did not do that. Post-replacement, the unit could have generated more than it did (the yellow plus the red in Figure 3), by running at full power at night. It did not do that. Pre-replacement and post-replacement, the unit ran the same way whenever it was able to run. In other words, the demand on the unit did not change, and did not cause the increase in generation. The increase was caused by the replacement.

(141) The Company's argument is like Mr. X who commits a crime and then claims he can prove that he did not do it. His proof is that he can show that Mr. Y could have done the deed. Mr. Y did not commit the crime; Mr. X did it. Nonetheless, Mr. X claims that the mere fact that Mr. Y could have done it proves that he did not do it. The Company's argument really is that simple – and that illogical.

(142) Finally, let us consider what would happen to the unit post-replacement if the boiler component was replaced and the demand on the unit increased, so the unit operated at higher power levels at night. The result is shown in Figure 4. The total generation is now greater – the total of the yellow and the red and the green. The additional red power was due solely to the replacement. Whether demand increased or stayed the same, the replacement would cause the added red power. The green power on all the nights but Wednesday is due solely to increased demand. Whether the replacement was done or not, the increased demand would cause the added green power (on the six days). The green on Wednesday is additional power that would only be generated if demand increased and the replacement was implemented.

(143) In the case of Monroe 2, the Company expected that the unit would experience an increase in EAF and an increase in demand. Figure 4 shows an example of a situation when EAF increased and demand on the unit also increased. In such a situation, it is always true that the generation by the unit will increase. It is also always true that some of the increase in generation will be due solely to the increase in EAF and some will be due to solely to the increase in demand. A small amount of the increase will be due to the combined effects of the increased EAF and the increased demand.

(144) In a situation when both EAF and demand on the unit increase, there will always be an increase in generation. In such a situation, some of the increase in generation is always due to the increase in EAF – the increase in generation would be less but for the increase in EAF. Despite what the Company claims, it can never be true that all of the increase in generation is due solely to the increase in demand.

I declare under penalty of perjury that the foregoing is true and correct.

Robert H. Koppe

Executed on July 23, 2010 in Boulder, Colorado

APPENDIX A

QUALIFICATIONS AND EXPERIENCE OF

ROBERT H. KOPPE

EMPLOYMENT HISTORY

<u>1968-1974 - Consolidated Edison Company of New York</u>

For his first two years with Con Ed, Mr. Koppe was an engineer in the company's Nuclear Engineering Division. For the next four years, he was manager of that Division and was responsible for licensing, safety analysis and engineering for safety-related projects for Con Ed's five nuclear units. His responsibilities included design review and licensing for the Indian Point 2 and 3 turnkey units; design review of modifications and additions to the three Indian Point units; and modifications, analysis, and engineering support for the nuclear portions of the Indian Point 1 and 2 units during operation. He participated extensively in the design, safety analysis, and licensing for the proposed Verplank 1 and 2 BWR units.

<u>1974-1994 S. M. Stoller/Hagler, Bailly, Boulder, CO</u>

In 1974, Mr. Koppe was employed by the Power Division of the S. M. Stoller Corp., which was purchased by RCG/ Hagler, Bailly in 1989. During his 20 years with the Division, he was deeply involved in the following areas of:

- developing data bases for power plant performance and power plant equipment reliability,
- analyzing the performance of power plants and power plant equipment,
- developing power plant performance standards,
- reducing power plant operating costs, and
- auditing/reviewing power plant performance and costs.

He is the author of numerous reports on these subjects and has presented expert testimony on them before regulatory bodies in Maine, Massachusetts, New York, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, Louisiana, Texas, Oklahoma, Wisconsin, Ohio and Ontario, and before several licensing boards of the Nuclear Regulatory Commission. He has also presented expert testimony in two civil suits.

<u>1994-present, Koppe Consultants Inc., Boulder, CO</u>

In 1994, Mr. Koppe left Hagler Bailly and formed his own consulting company. He has continued with the work he did at Hagler Bailly.

EDUCATION

- State University of New York, College of Forestry, BS, Wood Products Engineering, 1965.
- Ohio State University, MS, Nuclear Engineering, 1966.

In addition, Mr. Koppe completed all course work toward a Ph.D. in Nuclear Engineering at the Massachusetts Institute of Technology.

PROFESSIONAL EXPERIENCE

The following are some of the projects in which Mr. Koppe has had a major role, either as project manager or as a principal contributor. These projects all involved fossil-fired (primarily coal) power plants. Mr. Koppe worked on many other projects that involved nuclear power plants.

POWER PLANT PERFORMANCE TARGETS

- Studies to develop performance targets (Capacity Factor, Equivalent Availability Factor and Heat Rate) for many nuclear and fossil power units, including:
- nine fossil and four nuclear units owned by Atlantic Electric,
- eleven fossil and four nuclear units owned by Delmarva Power and Light,
- seven fossil units owned by Metropolitan Edison,
- seven fossil units owned by Philadelphia Electric,
- two fossil units and one nuclear unit owned by Southern California Edison,
- one nuclear and five fossil units owned by Rochester Gas and Electric,
- five fossil and four nuclear units owned by Virginia Power, and
- twelve fossil units owned by TransAlta (also included targets for O&M and capital additions costs).

AUDITS, REVIEWS AND STUDIES OF INDIVIDUAL UTILITIES, POWER PLANTS OR POWER PLANT OUTAGES

- An evaluation, for Virginia Power, of the performance of its five largest coal-fired units. The evaluation looked in detail at many recent or planned improvements in plant design and maintenance, and quantified the improvements in the performance of the units expected as a result.

- An evaluation, for Georgia Power, of its programs to improve the performance of its nuclear and fossil units, especially the Vogtle (nuclear) and Scherer (coal) units. The evaluation considered both design improvements and improvements in operations and maintenance, and quantified the costs and expected benefits of scores of improvements.

- An evaluation, for the Public Staff of the North Carolina Public Utilities Commission, of the life extension program proposed by Duke Power Company for eleven coal-fired units. The evaluation looked at the need for the life extension program, the improvements in the performance of the units expected to result from the program, and changes in program costs and plant outage times that might result if the program were carried out using schedules considerably different from the one proposed by Duke.

- An audit, for the New York Department of Public Service, of the availability and heat rate of Rochester G & E's one nuclear and five coal units. The audit included (1) comparison of RG&E's units with similar units in the industry, (2) evaluation of the management of the units and of various RG&E programs (such as maintenance, outage planning and plant modifications) as they affected availability and heat rate, (3) identification of programmatic or hardware charges that might improve availability or heat rate, and (4) prioritization of a number of proposed improvements based on cost-benefit evaluations of each improvement.

- An assessment, for the City of Cincinnati, of the costs that had been incurred to convert the Zimmer nuclear plant to coal, and a comparison of those costs to the anticipated costs of constructing a coal unit at a "greenfield" site. The "conversion" involved only a very modest use of equipment from the nuclear plant. The resulting plant is essentially a duplicate of the AEP design for 1300 Mw supercritical coal units.

- An assessment, for Houston Light and Power, of its proposed program for life extension of two older gas-fired units. These units had been mothballed and were being considered for refurbishment and life extension. The assessment focused on the scope of refurbishment that would be required and the performance (Equivalent Availability Factor) that could be expected from the units following that refurbishment.

- A study, for the California Department of Water Resources, of the expected capacity factor for a new coal-fired unit.

- An evaluation, for the Municipal Electric Association in Ontario, of Ontario Hydro's long term plans for its generating stations, which included 20 Candu-type nuclear plants and a number of coal-fired plants.

- Estimates, for an independent power producer, of the costs to build and operate a number of different power plants including a coal-fired plant, a combustion turbine plant and a combined cycle plant.

- Evaluations, for two different independent power producers, of the heat rates of their cogeneration facilities. The emphasis of these evaluations was the ability of the facilities to meet PURPA requirements for a QF.

- An evaluation, for Philadelphia Electric, of its coal plants at Eddystone and Cromby. The evaluation focused on performance changes to be expected as a result of new emissions control systems and many changes in plant design and operations.

- An assessment, for TransAlta (Alberta), of the expected performance and costs of its 12 coal power plants throughout their remaining lives. The assessment looked in detail at (1) historical performance and costs of the 12 units and of peer units throughout North America, (2) an assessment of the material condition of the plants done by an architect/ engineer, and (3) review of expected modifications and upgrades of plant equipment throughout remaining life.

STUDIES OF INDUSTRY WIDE POWER PLANT EXPERIENCE

- An analysis, for EPRI, of data in the North American Electric Reliability Council's Generation Availability Data System (NERC-GADS) to determine the impacts of various problems on fossil plant performance as a function of design and operating characteristics. This study was to assist EPRI in R&D planning and was not published.

- A study, and a later update, for EPRI, of the performance of nuclear and large fossil generating units and of the causes of outages and deratings at those units. The studies looked in detail at:
- how performance varied as a function of such factors as the size, age, and vintage of a unit;
- the impacts of each plant system and component on plant availability;
- the frequencies and duration of outages due to major problems; and
- the effects of various design and operating conditions on the frequencies of problems.

- A study, for EPRI, covering the historical performance of fossil-fired units and the relationship of this performance to major unit characteristics such as size, age, vintage, fuel, steam pressure, etc. The study (based on analysis of NERC-GADS data) covered all units sized 200 Mw and larger over the period from 1965 through 1984. The analysis examined both unit and system/component performance. (EPRI Report CS-5627)

DEVELOPMENT OF POWER PLANT DATA BASES AND RELIABILITY IMPROVEMENT PROGRAMS

- Preparation of the Generating Availability Data System (GADS) reporting manual for the North American Electric Reliability Council. Presentation of a series of workshops to teach utility personnel responsible for data reporting how to use the new reporting system.

- A series of six studies, for EPRI, to determine how power plant reliability/availability data systems could be improved. Interviews were conducted with utilities, equipment suppliers, architect/engineers, government agencies and operators of existing data systems -- as well as many non-utility organizations -- to determine what data were being collected, the uses being made of that data and the most effective ways to collect and to use data.

- Development, for EPRI and NERC, of a series of detailed examples showing use of NERC GADS data in utility decision making (EPRI Report NP 2167).

- Presentation of workshops sponsored by the Electric Power Research Institute on basic techniques in availability engineering, emphasizing use of NERC-GADS data. (EPRI Report NP-2166)

APPENDIX B:
GENERAL DISCUSSION OF THE PERFORMANCE
OF COAL-FIRED ELECTRIC GENERATING UNITS
AND MY METHODOLOGY FORANALYZING THAT PERFORMANCE

COAL UNIT OPERATION

In this Appendix, my descriptions of the industry are based on a combination of my experience working at individual units, my experience analyzing data on the industry, and industry-wide design data reported to GADS.

No generating unit can operate all the time. Every unit must shut down at least occasionally to overhaul equipment or to repair equipment that has failed. When a unit is shut down to overhaul or repair equipment, it is said to be in an outage. It is also said to be unavailable, since it is not available (not able) to generate electricity.

Typically, when a coal unit is operating, it will operate for much of the time at full power but will also operate for some of the time at less than full power. Operation at reduced power is due to deratings and, more importantly, to power reductions when demand for electricity is low, especially at night. The output factor for a unit is the ratio of the amount of power the unit actually generated to the amount it could have generated had it always operated at full power whenever it operated at all.

Each unit has a capability, also known as a rated output. This is the maximum amount of electricity the unit can generate on a day-to-day basis when all equipment is working properly. The capability of a unit changes as the temperatures of the air that is drawn into the boiler and of the water that is used to cool the condenser change with the seasons.

Sometimes, a unit is available but has some equipment problem that limits its output to less than its capability – that is, to less than full power. If a unit is limited to less than its capability, it is said to be derated or in a derating.

Some coal units are always, or almost always, operated whenever they are available. This is referred to as being base-loaded. Some base-loaded coal units always operate at the maximum output of which they are capable. Many others are sometimes operated at outputs lower than their capability, because there is not a need for all the power the unit could produce. A common situation is that a unit is operated at maximum capability during the day, when the use of electricity by consumers is highest, but may be operated at reduced output at night, when use of

electricity by customers is lowest. When a unit operates at an output lower than what it is capable of, this is referred to as load following or economic dispatch.

OUTAGES AND DERATINGS

Outages at a generating unit are broadly classified as planned or unplanned. It has been traditional in the utility industry to shut down each unit for a planned outage once each year. The schedule of a planned outage and the work to be done during the outage are planned months or, in the case of major work, years in advance. Outages are usually scheduled for the spring or fall when customers' demand for electricity is relatively low. During a planned outage, work is usually done on many parts of the unit. Traditionally, a coal unit would have a planned outage of a few weeks each year, where the major work would be inspection and overhaul of the boiler. Every fifth year, the planned outage would be longer (typically about 6 weeks). During these longer outages, major overhaul work would be done on the turbine-generator, in addition to the usual boiler work. In the 1970s, large coal units were averaging about 39 days per year for planned outages.[65] By the late 1990s, this had decreased to about 28 days per year.[66] The decrease in outage time was due to a combination of shorter outages and fewer outages, that is, more time between outages. When a unit has major equipment problems, it is often necessary to have a planned outage every year so that the equipment can be inspected and repaired. Thus, replacement of any major problem components (usually with improved designs) is often a requirement for increasing the time between planned outages.

Between planned outages, a coal unit is expected to be available (capable of running) most of the time. As a unit operates, individual components sometimes fail and some of these failures make it necessary to shut down before the next planned outage. Such a situation is referred to as an unplanned outage. Generally, the unit cannot be restarted until the failed component is repaired. During an unplanned outage, repair efforts are focused on the problem that caused the outage. To the extent that manpower and time are available, other equipment may be repaired, but work is generally limited to what can be done within the time it takes to repair the problem that caused the outage. Some unplanned outages, such as those caused by failures of instruments or controls, may last less than an hour. Others, such as those caused by a catastrophic failure of a turbine or generator, may last many months. Throughout the industry, the most common cause of unplanned outages is failures (leaks) of boiler tubes. Outages for boiler tube leaks typically last a day to a few days. Unplanned outages are characterized as forced or maintenance. For a maintenance outages, the equipment problem(s) is (are) such that the utility could have delayed the start of the outage until after the following weekend, if this was economically advantageous.

---

[65] Nuclear and Large Fossil Unit Operating Experience EPRI NP-1191, September 1979, page 5-71.
[66] Generation Availability Report, 1995-1999 NERC GADS.

For a forced outage, the equipment problem is such that the start of the outage could only be delayed for a shorter time period, or not at all.

The impact of outages on coal unit availability decreased dramatically during the 1980s and 1990s. In the mid-1970s, the largest coal units (those rated 600 to 1300 MW) were shut down an average of 99 days per year for planned and unplanned outages. By the late 1990s, this had decreased to only 48 days per year, so that the units were able to operate for an average of 51 additional days each year. This was a result of improved performance of many different components in the units. For example, in the 1970s, the large coal units shut down an average of 5.6 times per year to repair boiler tube leaks. By the late-1990s, this had decreased to 2.9 times per year, despite the fact that the units were running more and were older. (The average age of all the largest coal units was only a few years in the 1970s, and had increased to 20 years by the late 1990s.)[67] The most important reason for this improvement has been the fact that problem components have been replaced with components of improved design at many units.

As I mentioned earlier, some equipment problems can limit the electric output from a unit to something less than its capability (less than full power). Some common causes of deratings at coal units are problems with the coal pulverizers and with other coal handling equipment. Like outages, deratings reduce the amount of electricity a unit is available to generate. Consider a unit that has a capability of 500 MW. For ten hours, the maximum output from the unit is limited to 450 MW due to a problem with a pulverizer. We say that the unit was derated by 50 MW (500 minus 450) for 10 hours. The unit was unable to generate 500 MW-hours (50 MW * 10 hours). This is the same as the amount the unit could not generate if it were shut down for one hour (500 MW * 1 hour). We say that the unit lost one equivalent full power hour (EFPH) of EAF (possible generation) as a result of the pulverizer problem.

MEASURES OF OPERATING UNIT PERFORMANCE

For the issues in this case, the most important aspects of the performance of a coal unit are:

- how much electricity could the unit have generated; and
- how much did it actually generate?

As described in the preceding, the availability of a unit to generate electricity is sometimes limited by outages and/or deratings to overhaul or repair components. Even when a unit is available to generate power, the utility may choose to not run it or to run it at less output than it is capable of at the moment. Typically, this would occur at times when the use of electricity by customers is less and when other units are available to generate electricity at a lower cost.

---

[67] Data for the 1970s are from Nuclear and Large Fossil Unit Operating Experience EPRI NP-1191, 9/79; Data for the 1990s are from Generation Availability Report - 1995-1999, NERC GADS.

<u>Actual Production of Electricity.</u> The standard measure of actual electricity production during a time period is called capacity factor (CF). It is calculated as the actual generation for the time period, divided by maximum possible generation (what the unit could have produced had it run continuously at full power). Consider a unit that has a capability to generate about 700 megawatts of electricity. If that unit ran perfectly for a year (8760 hours), it would produce 700 * 8760 = 6,132,000 megawatt-hours. This is the maximum possible output for the year. If the unit actually produced that much output, we would say that it had a capacity factor (CF) of 100%. If the unit produced 75% of the maximum possible output (.75 * 6,132,000 = 4,599,000 megawatt-hours), we would say that it had a CF for the year of 75%. There are many ways a unit could achieve a CF of 75%. For example it could run at full power (700 megawatts) for 75% of the hours (.75 * 8760 = 6570 hours) and be shut down the rest of the time. Then its output would be 6570 * 700 = 4,599,000. Or, the unit could run for all 8760 hours in the year at 75% of full power (.75 * 700 = 525 megawatts). The output would be 525 * 8760, which again is 4,599,000 megawatt-hours.

<u>Possible Generation of Electricity.</u> There are two measures that give an indication how much a unit could have generated if asked: the availability factor (AF) and the equivalent availability factor (EAF). AF measures the percentage of the time that a unit was able to generate electricity. It does not take any account of whether the unit was able to generate at full power or was limited to some lower output. An AF of 70% would mean that the unit had, in theory at least, been available to operate at some power level for 70% of the time. EAF is a more complete measure of what a unit could in theory have done, since it also takes account of any limitations on the power level at which a unit could have operated. The following simplified example illustrates the calculation of AF and EAF. A hypothetical unit was shut down for equipment repairs or maintenance for 2,190 hours in a year. There are 8,760 hours in a year. We would say that the unit was unavailable 25% of the time (2190/8760 = .25). Therefore, the unit was available to generate electricity 75% of the year: it had an AF of 75%. During the time it was available, the unit was limited (derated) to 80% of full power for 1,000 hours. The unit could not have generated 20% of its rated output for 1,000 hours. This has the same effect as (is equivalent to) being shut down for 200 hours. Therefore, we say that the unit lost 200 Equivalent Full Power Hours (EFPH) due to the derating. Therefore, we say that the unit was unavailable for 2,390 EFPH (2,190 due to outages and 200 due to deratings).[68] We also say that the unit had EAF losses of 2,390 EFPH for the year. The EAF for the unit was 72.72% (100 * (1 – (2390 / 8760)). Note that EAF cannot be measured directly. It is calculated by starting with 100% and then subtracting out all the EAF losses (EFPH that could not have been generated) as a result of each outage and derating that occurred during the time period.

[68] One hour of outage is a loss of one EFPH.

The EAF and CF for units within the industry followed the same pattern as industry outage experience: the amount of outage time decreased as the years passed, so EAFs and CFs increased. In the 1970s the average reported EAF of larger coal units was very poor (around 65%). Through the 1980s and 1990s, the average reported EAF for large coal units improved steadily. By the late 1990s (1995-1999), the average EAF was about 85%. The actual improvement in achievable CF was considerably greater than the 20 percentage points implicit in the preceding. The reason for this is simple. In the 1970s and 1980s, coal units spent a relatively large fraction of the time in reserve shutdown. Thus, the calculated EAFs exceeded the achievable CFs by a considerable amount. (See preceding section.) By the late 1990s, coal units were spending a smaller fraction of the time in reserve shutdown, so the amount by which calculated EAFs exceeded the achievable CFs decreased. In the late 1990s, capacity factors for all large coal units averaged about 70%.[69]

The utility industry has collected data on the performance of generating units for decades. Initially, the data were collected by the Edison Electric Institute, an industry lobbying organization. Data collection was taken over by the North American Electric Reliability Council (NERC) in the late 1970s. Starting with 1982, NERC has collected generating unit operating data in a format called Generating Availability Data System (GADS). While reporting to GADS is voluntary, data are reported for most coal units in the United States and Canada, including the DTE units. There are three types of GADS data:

1. design;
2. performance; and
3. event.

GADS Design (Pedigree) Data comprise basic information on the design of a unit, including the size of the unit, the type of boiler, the boiler manufacturer, the kind of fuel burned, etc. Generally, these data are reported only once in the life of a unit. In a rare situation when the design of a unit is sufficiently changed, the design data would be changed accordingly. Performance data for each unit are reported on a monthly or quarterly basis. The data give basic information about the overall performance of the unit including:

- the capability of the unit;
- how long the unit ran;
- how often it started up;
- how much electricity it generated;
- how much fuel it burned; and
- the basic characteristics of the fuel burned.

[69] Nuclear and Large Fossil Unit Operating Experience, EPRI NP-1191, 9/79; and Generation Availability Report, 1995-1999, NERC GADS.

For any unit, GADS event data are reported for each event (outage, reserve shutdown, or derating).[70] For each event, the data include:

- the type of event (e. g., forced outage, maintenance outage, planned outage, derating, reserve shutdown);
- the dates and times the event started and ended;
- the power output to which the unit was limited (this is zero for outages and reserve shutdowns and some non-zero value for deratings); and
- the cause of the event (this is described by a code that is chosen from a list of codes that correspond to various parts of a unit and problems affecting those parts, and by a brief narrative).

For my analyses, event data were particularly important. These data tell how much of the potential output of electricity from a unit could not be generated as a result of any particular component in the unit.

[70] There is also an event type called “non-curtailing”, which is not relevant to my analyses.

KOPPE DECLARATION

APPENDIX C:

FIGURES 1-4

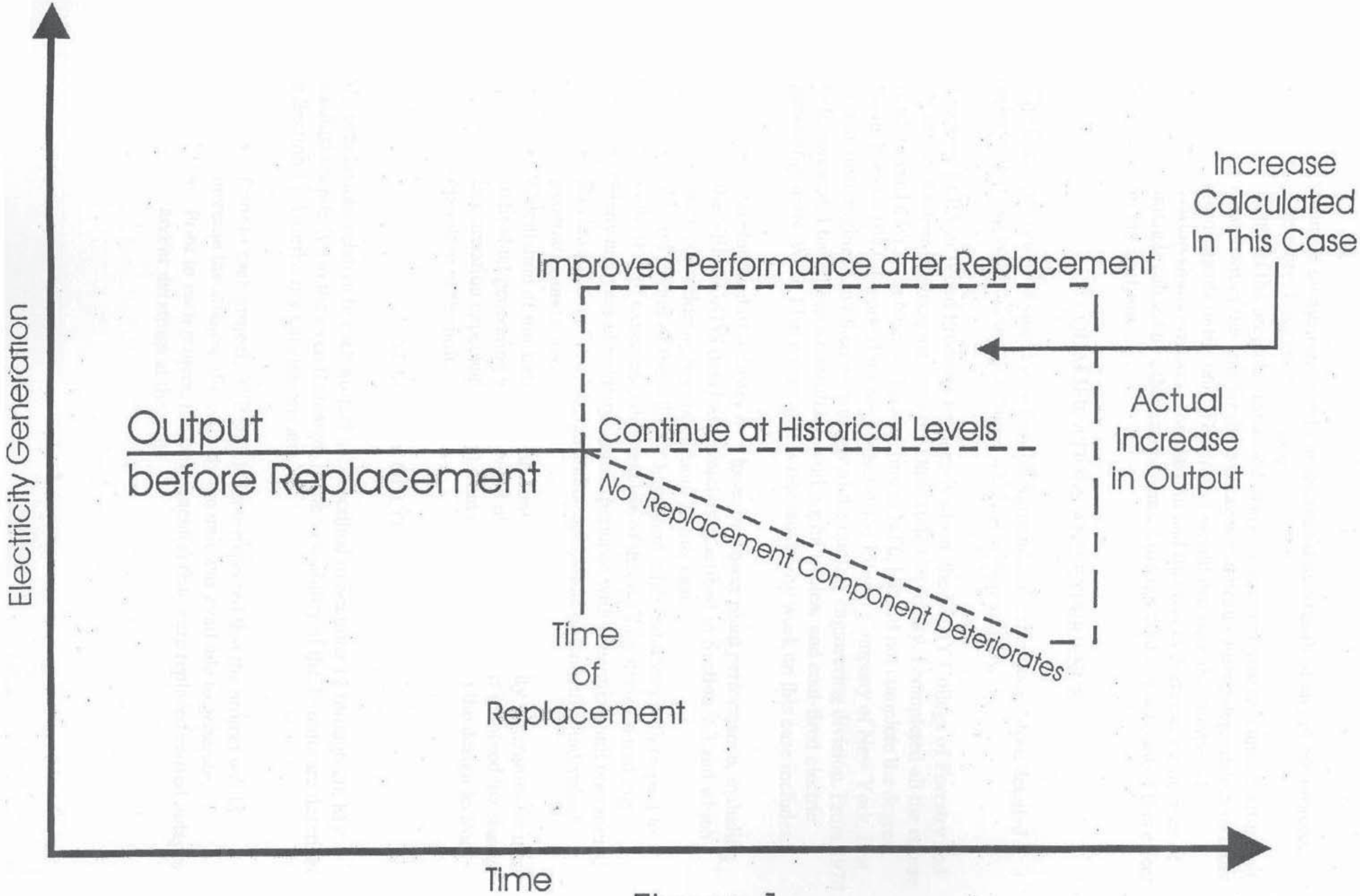
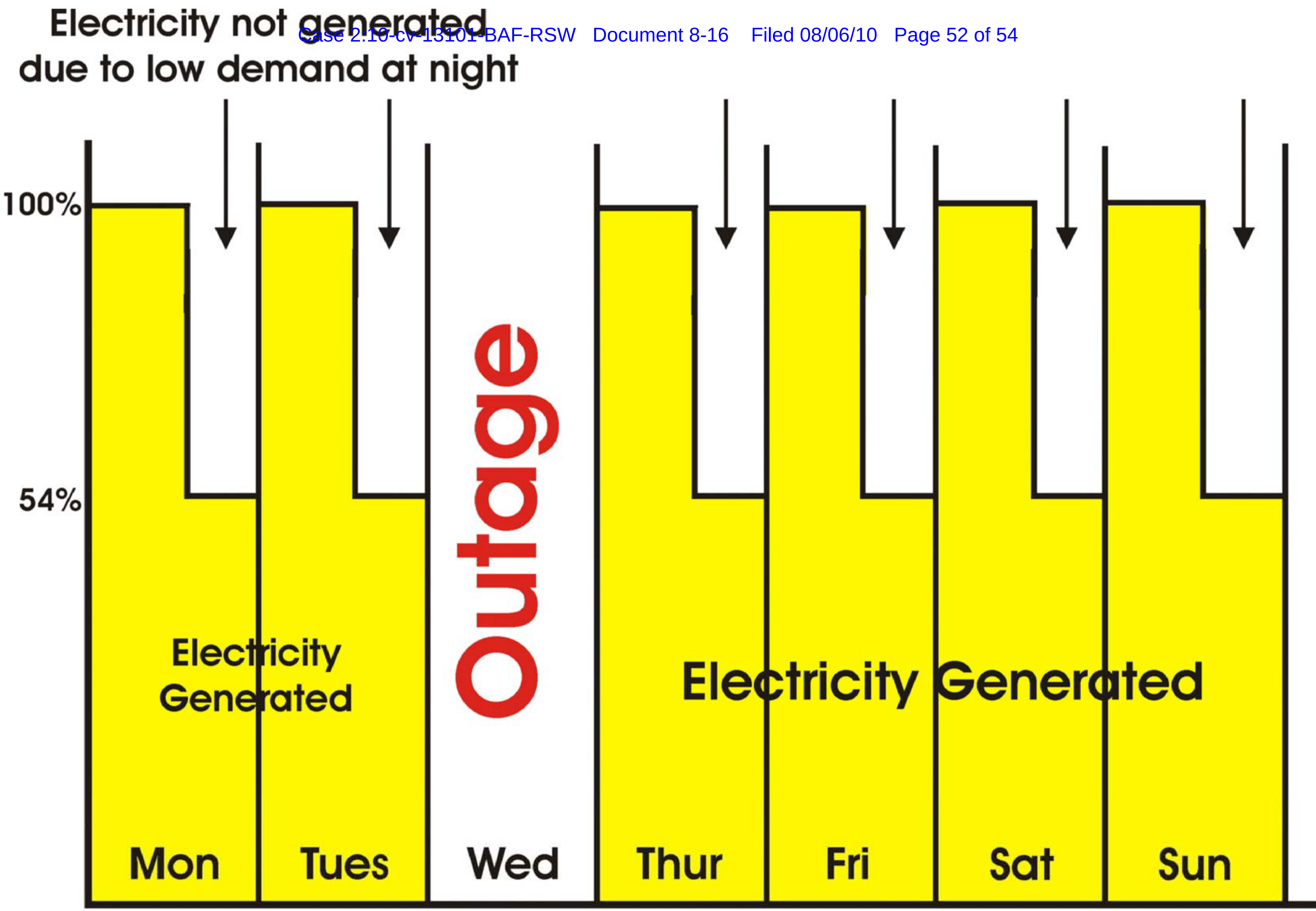
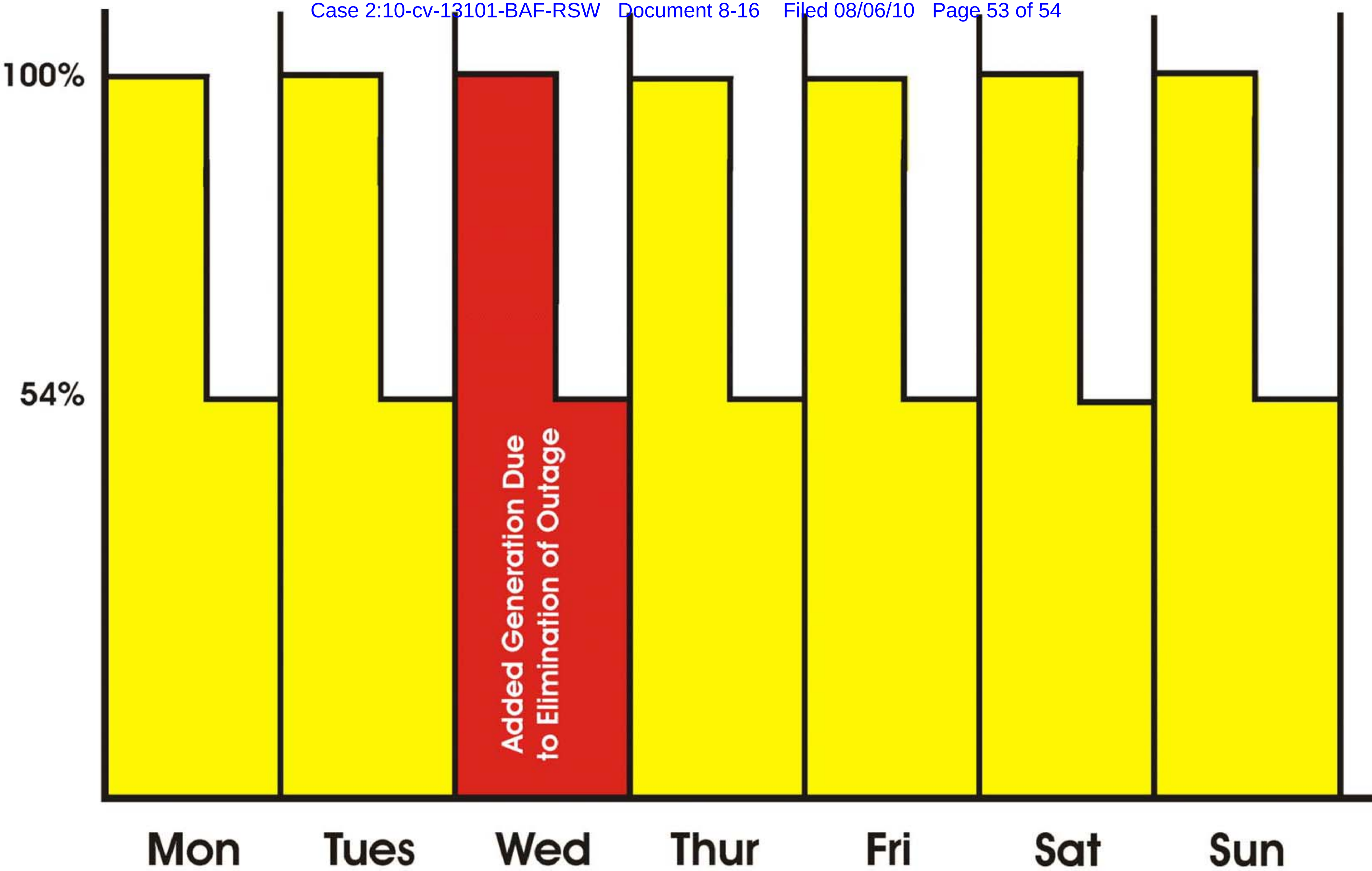


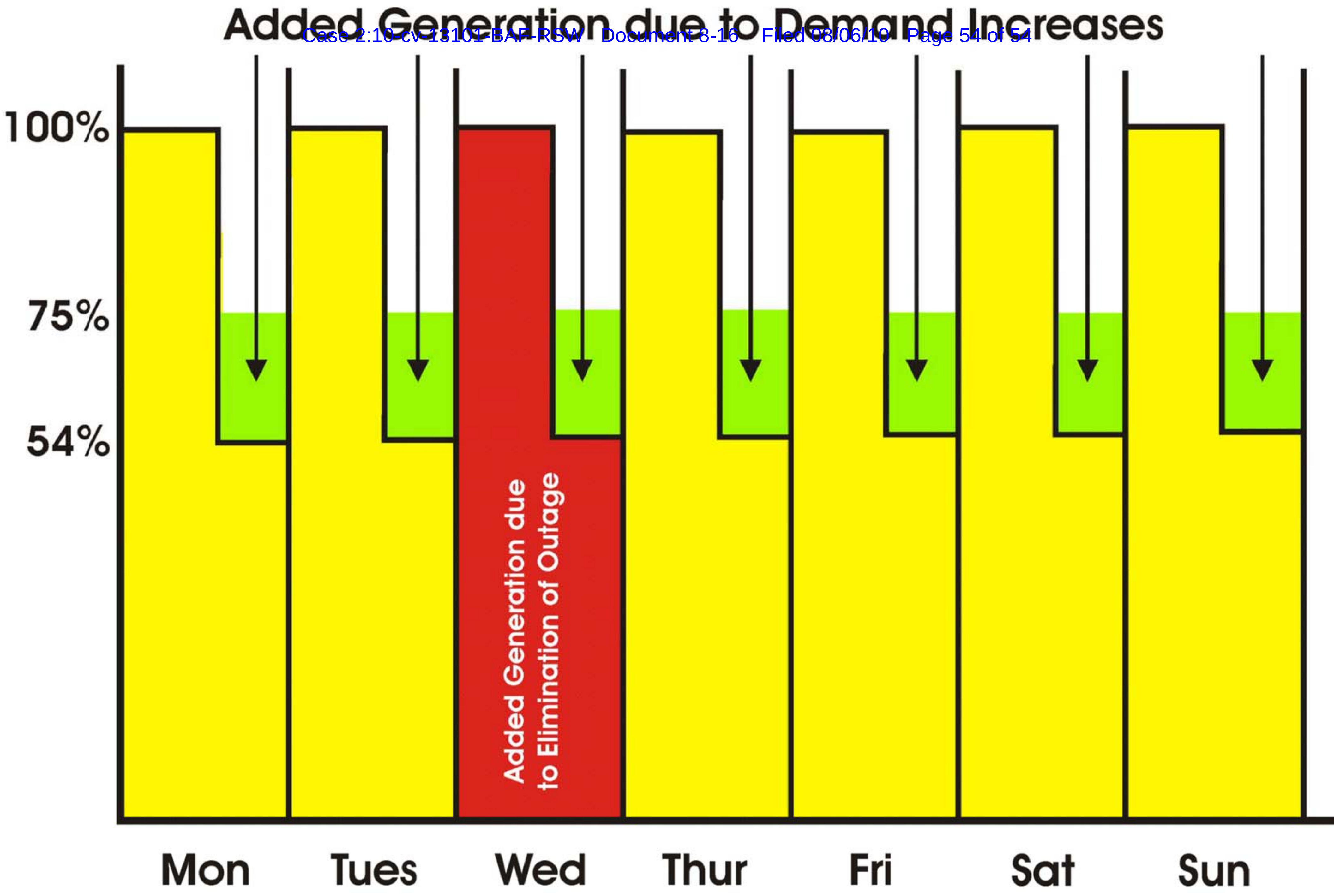
Figure 1
Calculation of Effect of
Component Replacement on
Generation of Electricity



Idealized week with a one-day outage



Idealized week showing additional
Generation if one-day Outage Eliminated



Idealized Week Showing Additional Generation if one-day Outage Eliminated and Demand Increases